MASTERS ENERGY INC.

Moving forward

2004 ANNUAL REPORT

CORPORATE PROFILE

Masters Energy Inc. is an Alberta-based corporation engaged in the acquisition, exploration and development of petroleum and natural gas reserves in western Canada. Masters common shares are listed on the Toronto Stock Exchange under the trading symbol "MSY".

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ABBREVIATIONS

OIL AND NATURAL GAS LIQUIDS

bbl	barrel
mbbls	thousand barrels
mmbbls	million barrels
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
mboe	thousand barrels of oil equivalent
NGL	natural gas liquids

NATURAL GAS

mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
GJ	gigajoule

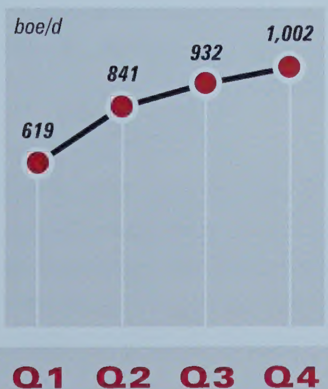
OTHER

AECO	EnCana Corporation natural gas storage facility located at Suffield, Alberta
°API	Specific gravity of crude oil measured on the American Petroleum Institute gravity scale (28° API or higher is generally referred to as light crude oil)
ARTC	Alberta Royalty Tax Credit
boe	Barrel of oil equivalent of crude oil and natural gas on the basis of 1 boe equals 6 mcf of natural gas
US	United States
WTI	West Texas Intermediate, the reference price paid in US dollars at Cushing, Oklahoma for crude oil of 40°API

HIGHLIGHTS

Years ended December 31	***2004***	***2003*** [(1)]
Financial *($ thousands, except per share amounts)*		
Gross revenue	**11,709**	192
Cash flow from operations	**5,634**	(67)
Per share - basic	**0.42**	(0.02)
- diluted	**0.41**	(0.02)
Net earnings (loss)	**428**	(110)
Per share - basic	**0.03**	(0.03)
- diluted	**0.03**	(0.03)
Capital expenditures	**10,920**	7,393
Working capital (deficit)	**(4,116)**	9,390
Operations		
Production		
Crude oil *(bbls/d)*	**558**	426
NGL *(bbls/d)*	**7**	1
Natural gas *(mcf/d)*	**1,706**	171
Total production *(boe/d at 6:1)*	**849**	455
Average sales price		
Crude oil *($/bbl)*	**36.51**	27.72
NGL *($/bbl)*	**44.25**	43.34
Natural gas *($/mcf)*	**6.59**	7.19

(1) Masters Energy Inc. commenced oil and gas operations on December 22, 2003 with the acquisition of the Little Bow property in southern Alberta. Average daily production for 2003 is reported from the date of acquisition.



2004 Production

2004 Revenue

2004 Cash Flow

TO OUR SHAREHOLDERS

Masters Energy Inc. has achieved significant progress since incorporation in August 2003. We started as a private company with no assets and now, as a public company, we are pleased to advise our shareholders that our production at the time of this report is approximately 1,300 boe/d.

In the fourth quarter of 2003, Masters raised $17.8 million by issuing equity and, in December 2003, we purchased the Little Bow property. The acquisition of Little Bow provided Masters with a core producing area which we have developed into a strategic asset. In February 2004, we merged with Terraquest and moved forward with an active drilling program during 2004. A significant feature of the Terraquest acquisition is a large undeveloped land base with numerous exploration and development prospects and several producing properties. As well, the amalgamation with Terraquest, a public company, provided liquidity for our shareholders.

Masters primary activities in 2004 focused on achieving several objectives:

- *build a strong production base to provide a foundation for future growth;*
- *optimize acquired producing assets;*
- *evaluate and exploit our large undeveloped land base;*
- *enhance liquidity for shareholders by increasing awareness in the financial community with respect to Masters activities; and,*
- *increase shareholder value.*

We accomplished or exceeded these goals in 2004 as outlined below:

- *increased production rates in each fiscal quarter by exploiting Masters asset base;*
- *acquired Little Bow and Terraquest creating a solid base of producing assets;*
- *commissioned an independent engineering firm to complete a reservoir simulation study of Little Bow which indicates that a significant amount of incremental oil could be recovered with infill drilling and waterflood optimization;*
- *successfully tested several exploration concepts on our undeveloped land base which will result in follow-up drilling in 2005;*
- *enhanced shareholder liquidity by amalgamating with Terraquest and initiating public trading of Masters shares; throughout 2004, daily trading volumes increased significantly; and,*
- *increased Masters net asset value per share by 44 percent.*

In addition to satisfying these primary objectives, Masters continues to perform well. Finding and development costs since inception are $12.05 per boe on a proved plus probable basis, resulting in a recycle ratio of 1.8 and demonstrating efficient use of capital. Masters is also working diligently to decrease operating expenses. Since the 2004 second and third quarters, we have lowered average operating expenses from approximately $10.00 per boe to a fourth quarter rate of $8.78 per boe with an expectation of lower costs in 2005.

Masters strategy for 2005 will build on our early success. We will continue to:

- *strengthen our asset base by exploiting our undeveloped lands in Alberta;*
- *focus on building value in our core producing asset at Little Bow through infill drilling and waterflood optimization; results to date from drilling our first phase of infill wells in January 2005 have exceeded our expectations; and,*
- *invest capital at expenditure levels approximately equal to cash flow and utilize our debt capacity to take advantage of acquisition opportunities.*

Masters forecasts an annual increase in production of 75 percent to 1,500 boe/d, capital expenditures of $12 million, drilling of 20 to 25 wells and cash flow of approximately $11 million. Our forecast currently assumes no acquisitions during 2005. The market for acquisitions has been very competitive recently and acquisitions have been relatively expensive. However, Masters will continue to pursue the purchase of assets where there is a strategic fit.

The current business environment for the oil and gas sector is very attractive. High commodity prices created by high demand for our product, relatively low interest rates, high demand for energy stocks and reasonable access to capital markets underpin a strong business environment. This also creates challenges with respect to the high cost of acquisitions, pressure on finding and development costs, elevated competition for oilfield supplies and services and increasingly challenging surface access issues. Masters is well positioned to take advantage of opportunities and we believe we can effectively manage the associated challenges in this vibrant business environment.

Masters is fortunate to have an strong team of people. The combination of our excellent team, significant investment opportunities, strong balance sheet, solid foundation of properties and attractive business fundamentals in the oil and gas sector creates a strong sense of optimism for our future.

In summary, I believe that Masters has delivered a significant number of accomplishments during our short corporate life. These achievements have only been possible with contributions from all Masters stakeholders. On behalf of the Board of Directors, I sincerely thank those individuals for their effort and support.

Geoffrey C. Merritt
President and Chief Executive Officer

March 3, 2005

MANAGEMENT'S DISCUSSION & ANALYSIS

ADVISORIES

Management's discussion and analysis ("MD&A") of Masters Energy Inc. ("Masters" or "the Company"), provided as of March 3, 2005, should be read in conjunction with the audited financial statements presented within this annual report.

Basis of presentation *- The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and measurement currency is the Canadian dollar.*

Non-GAAP measurements *- The MD&A contains the term 'cash flow from operations', which should not be considered an alternative to, or more meaningful than net earnings or cash flow from operating activities as determined in accordance with GAAP as an indicator of the company's performance. Masters determination of cash flow from operations and cash flow per share may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the statements of cash flows in the audited financial statements. Masters presents cash flow from operations per share which is prohibited under GAAP. Per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.*

Boe presentation *- The calculations of barrels of oil equivalent ("boe") are based on a conversion rate of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil. Boe units may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Forward-looking information *- This MD&A contains forward-looking or outlook information with regard to Masters within the meaning of applicable securities laws. Forward-looking statements may include estimates, plans, expectation, forecasts, guidance or other statements that are not statements of fact. Masters believes the expectations reflected in such forward-looking statements are reasonable. However, no assurance can be given that such expectations will prove to be correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, the company's ability to replace and expand oil and gas reserves, the sources and adequacy of funding for capital investments, future and current growth prospects and the company's expected financial requirements, the cost of future reclamation and site restoration, the company's ability to enter into or renew leases, the company's ability to secure adequate product transportation, changes in environmental and other regulations and general economic conditions. These statements speak only as of the date of this MD&A and Masters does not undertake an obligation to update our forward-looking statements except as required by law.*

MANAGEMENT'S DISCUSSION & ANALYSIS

ACQUISITION

Masters acquired Terraquest Energy Corporation ("Terraquest") by way of a plan of arrangement whereby Terraquest and Masters amalgamated effective February 26, 2004. At the time of the acquisition, Terraquest was producing approximately 400 boe/d, 60 percent of which was natural gas. Terraquest's attraction to Masters was an extensive base of undeveloped land with a significant number of drilling prospects. Terraquest owned and primarily operated 83,000 net acres of undeveloped land having an average working interest of 60 percent.

The Terraquest purchase was valued based on the discounted proved plus probable reserves acquired as determined by an independent reserves evaluation. Masters staff internally estimated land cost values. The cost of the purchase, based on the above valuation methods, was as follows.

($ thousands)		
Property and equipment	$	19,584
Future tax asset		903
Working capital deficiency		(694)
Fair value of hedging commitment		(199)
Bank debt		(7,032)
Asset retirement obligations		(1,770)
Total purchase price	$	10,792

OVERVIEW

Masters Energy Inc. was incorporated under the Alberta Business Corporations Act on August 28, 2003. During the fall of 2003, Masters completed a private placement of 17,752,000 special warrants for gross proceeds of $17.8 million. On December 22, 2003, Masters closed the acquisition of producing oil and gas properties in the Little Bow area of southern Alberta. At the time this property was acquired, daily production was approximately 450 boe/d comprised of 90 percent crude oil and 10 percent natural gas.

On February 26, 2004, Masters and Terraquest, a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco Common Share for every 12 common shares of Terraquest and Masters shareholders received one Amalco Common Share for every two common shares of Masters. After giving effect to the transaction, Amalco has approximately 14.4 million common shares outstanding.

The consequence of the reverse take-over and amalgamation of Terraquest on February 26, 2004 was the loss of any relevant comparative analysis for Masters in the 2003 accounting period. Year-over-year operational and financial comparatives will provide useful information with the publishing of our 2005 annual report.

In 2004, Masters has been actively drilling in the southern and central regions of Alberta. Of 19 wells drilled or recompleted in 2004, 10 were successful natural gas wells.

During the fourth quarter of 2004, Masters drilled four wells (2.4 net) resulting in one natural gas well and three abandoned wells. At the end of 2004, three wells were waiting for pipeline tie-ins. We expect to complete the well tie-ins during the early part of 2005.

MANAGEMENT'S DISCUSSION & ANALYSIS

For the year ended December 31, 2004 and the period August 28, 2003 to December 31, 2003

PRODUCTION

Masters 2004 results from the date of amalgamation, February 26, 2004, include production volumes from the Terraquest properties. This report incorporates Masters results from January 1 to February 26, 2004 plus the results of the amalgamated entity from February 26 to December 31, 2004.

	2004	2003(1)
Annual production		
Crude oil *(bbls)*	**204,049**	4,259
NGL *(bbls)*	**2,550**	6
Natural gas *(mcf)*	**624,536**	1,713
Total *(boe)*	**310,688**	4,551
Daily production		
Crude oil *(bbls/d)*	**558**	426
NGL *(bbls/d)*	**7**	1
Natural gas *(mcf/d)*	**1,706**	171
Total *(boe/d)*	**849**	455

(1) Operations commenced December 22, 2003 upon closing the acquisition of the Little Bow property in southern Alberta. Therefore, daily production is calculated from the date operations began until 2003 year-end.

Volume for the year ended December 31, 2004 averaged 849 boe/d day with a production mix of 67 percent oil and NGL and 33 percent natural gas. The average production for the month of December 2004 was 1,055 boe/d, of which 57 percent was oil and NGL and the balance, natural gas. Production increased during the 2004 year as a result of successful drilling and tie-in of natural gas wells.

Oil and gas operations commenced on December 22 with the acquisition of the Little Bow property in southern Alberta. From the date of acquisition until the 2003 year-end, production averaged 455 boe/d with a production mix of 94 percent oil and NGL and the remainder, natural gas.

Based on the drilling activity budgeted for 2005 and production expected from existing producing properties, Masters forecasts a production rate of approximately 1,500 boe/d with a production mix of 58 percent oil and NGL and 42 percent natural gas.

PRICES

	2004	2003
Crude oil - before hedging *($/bbl)*	**37.66**	27.72
Hedging settlement *($/bbl)*	**(1.15)**	-
Crude oil - after hedging *($/bbl)*	**36.51**	27.72
NGL *($/bbl)*	**44.25**	43.34
Natural gas *($/mcf)*	**6.59**	7.19

MANAGEMENT'S DISCUSSION & ANALYSIS

The commodity prices recorded in the above table are net of hedging settlements of $0.2 million. The hedging contract was obtained with the acquisition of Terraquest Energy Corporation. The loss recorded for the year was the balance in excess of the fair value of the hedging contract liability recorded at the time of the acquisition.

West Texas Intermediate ("WTI") is the benchmark for North American oil prices and is the crude type against which NYMEX futures contracts are priced. Canadian crude oil prices are based on refiners' postings at hubs such as Edmonton and Hardisty, Alberta. Canadian postings are based on the WTI price at Cushing, Oklahoma less a transportation differential, the United States/Canadian ("US"/"Cdn") currency exchange rate, adjusted for relative quality and regional market conditions.

During 2004, North America experienced historically high price levels for WTI crude oil due to concerns about supply. As a result, the average price for a barrel of WTI crude oil during 2004 increased over $10.00(US) to $41.42(US). The Canadian dollar strengthened relative to the US dollar during the course of the year. The average currency exchange rate for $1.00 Cdn increased from $0.71(US) in 2003 to $0.77(US) in 2004. As a result, this lowered the price received for delivery of crude within Canadian markets. The quality price differential postings on medium type crudes also experienced a negative effect during 2004. The average differential between Edmonton light sweet crude postings and Hardisty Bow River medium crude was approximately $15.00 per bbl versus the historical average of $9.00 per bbl.

Masters average field price in 2004 was $37.66 per bbl versus $52.90 per bbl for light sweet postings at Edmonton, Alberta. Overall, Masters 2004 crude oil production was 84 percent medium and 16 percent lighter gravity crude.

US natural gas prices are typically referenced from NYMEX at the Henry Hub, Louisiana while Canadian prices are referenced at NOVA Inventory Transfer ("NIT") or the AECO Hub. All of Masters 2004 natural gas was sold to the spot market according to the AECO reference price. Masters did not enter into any fixed or hedged type gas sales contracts during 2004.

The price received for 2003 was limited to the period of production for the final 10 days of the calendar year.

Masters management complies with a Risk Management Policy approved by the Board of Directors. The objective of our risk management activities is to reduce exposure to decreases in commodity prices that would materially impact the cash flow expected to fund capital spending and, ultimately, Masters growth. Any transactions Masters would enter into would be with credit worthy purchasers and would be for a period of less than one year. To the extent that Masters has sufficient physical volumes available to meet the obligation of these transactions, we would limit the transacted volume to no more than 50 percent of forecasted production.

Masters 2005 budget used forecasted prices of $35.00(US) per bbl of WTI crude oil and $6.50(Cdn) per mcf of natural gas at the wellhead. The 2005 budget estimated the forecasted US/Cdn foreign currency exchange rate to average $0.80(US) per $1.00(Cdn).

MANAGEMENT'S DISCUSSION & ANALYSIS

REVENUES

($ thousands, except as indicated)	*2004*	*2003*
Crude oil	**7,685**	118.0
Hedging charge	**(234)**	-
Crude oil, after hedging charge	**7,451**	118.0
NGL	**113**	0.3
Natural gas	**4,116**	12.3
Total resource	**11,680**	130.6
Interest and other	**29**	61.5
Total	**11,709**	192.1
Total per boe *($)*	**37.69**	42.21

Resource revenues for 2004, totaled $11.7 million as commodity prices remained strong and production volumes continued to grow. Oil revenues were partially offset with a $0.2 million loss recorded for the balance remaining on the hedge contract assumed through the acquisition of Terraquest. The hedging contract expired on December 31, 2004. The oil and natural gas revenue for 2003 was $0.1 million as sales from operations were limited from the time to the period of time following the acquisition of the Little Bow property.

Interest and other income earned on surplus cash totaled $29,264 during 2004 versus $61,471 for 2003. During 2004, surplus cash was invested in exploration and development capital spending and acquisitions and, as a result, interest income was lower.

Based on forecasted production volumes and commodity prices, Masters expects oil and gas revenues to increase 70 to 75 percent during 2005.

ROYALTIES

($ thousands, except as indicated)	*2004*	*2003*
Crown	**2,122**	23.5
ARTC	**(184)**	-
Crown, net of ARTC	**1,938**	23.5
Freehold and other	**172**	0.2
Net royalties	**2,110**	23.7
Per boe *($)*	**6.79**	5.20
Average royalty rate, before hedge charge *(%)*	**17.7**	18.1
Average royalty rate, after hedge charge *(%)*	**18.1**	18.1

Royalties for 2004, net of Alberta Royalty Tax Credit, totaled $2.1 million resulting in an average royalty rate relative to oil and gas revenues of 18 percent. The composition of the royalty expense incurred during the year was 92 percent paid to the crown and the balance, to freehold royalty owners. Royalties for the year were $6.79 per boe.

MANAGEMENT'S DISCUSSION & ANALYSIS

For 2003, the royalty rate averaged 18 percent of oil and gas revenues. There was no ARTC during the period as the Little Bow property was considered a restricted resource property for ARTC purposes.

We expect forecasted royalty rates for 2005 to be consistent with historical rates. We anticipate maximizing Masters ARTC claim on crown royalties during 2005.

OPERATING EXPENSES

($ thousands, except as indicated)	**2004**	**2003**
Production expenses	**2,816**	37.0
Transportation costs	**37**	-
Total operating expenses	**2,853**	37.0
Per boe *($)*	**9.18**	8.13

Operating expenses for the year ended December 31, 2004 were $2.9 million. This equated to an average cost of $9.18 per boe produced. Operating expenses were higher than anticipated due to well servicing, plant turnaround and maintenance activities carried out at the Little Bow facilities during the 2004 summer. Included in 2004 operating expenses are transportation costs incurred on contracted natural gas deliveries.

Operating expenses for 2003 were limited to the production from the Little Bow field.

Masters expects operating expenses per boe to decrease with higher production volumes as fixed costs are spread over a larger production base for 2005. Due to increased industry demand, variable costs such as utility and service fees will partially offset this anticipated decrease in operating expenses.

Netback analysis *($ per boe)*	**2004**	**2003**
Oil and gas revenues, before hedge charge	**38.35**	28.70
Hedge charge	**(0.75)**	-
Oil and gas revenues, after hedge charge	**37.60**	28.70
Royalties, net of ARTC	**(6.79)**	(5.20)
Operating expenses	**(9.18)**	(8.13)
Netback	**21.63**	15.37

GENERAL AND ADMINISTRATIVE

($ thousands, except as indicated)	**2004**	**2003**
Gross general and administrative	**1,529**	192
Operating recoveries	**(121)**	-
Capitalized expenses	**(504)**	-
General and administrative, before stock-based compensation	**904**	192
Future stock-based compensation expense	**173**	38
Total general and administrative expense	**1,077**	230
General and administrative expense per boe *($)*	**3.47**	50.48

MANAGEMENT'S DISCUSSION & ANALYSIS

During 2004, net general and administrative (G&A) expenditures totaled $1.1 million. G&A averaged $3.47 per boe for the year ended December 31, 2004. During the year, Masters capitalized $0.5 million of G&A associated with exploration and development activities. Masters capitalizes G&A related to exploration and development activities because these costs are associated with adding reserves. G&A expenses for the period include a non-cash provision of $0.2 million for future stock-based compensation. G&A for the year included several one-time costs associated with start-up and amalgamation.

G&A expenditures for 2003 accumulated during the period from Masters incorporation in August 2003 until December 31, 2003. That period's G&A per boe is high because oil and natural gas production occurred only from December 22 to December 31, 2003.

We anticipate that total G&A expenses for 2005 will be similar to 2004. Based on forecasted production and capital spending, we also expect 2005 staffing will be similar to 2004. As new production is brought on stream, we expect costs per boe to decrease.

INTEREST EXPENSE

At year-end 2004, Masters had $3.4 million in bank debt. The average debt outstanding during the year was approximately $1.2 million. The change in the year-end balance over the average borrowing level was a result of the increased exploration and development activities during the latter half of the year. Masters average interest rate for borrowing during the year was 4.18 percent. Included with interest expense was $56,000 of Part XII tax on the unspent portion of 2003 flow- through share funding received and held after February 2004. The 2003 flow-through share funds were fully spent in 2004.

We anticipate debt levels and interest rates for 2005 will be similar to 2004. For 2005, we are estimating debt to cash flow ratio at approximately 0.4 to 1.

DEPLETION, DEPRECIATION AND ACCRETION

($ thousands, except as indicated)	2004	2003
Depletion	**4,283**	34
Depreciation	**13**	5
Accretion on asset retirement obligations	**171**	-
Total depletion, depreciation and accretion expense	**4,467**	39
Depletion, depreciation and accretion expense per boe ($)	**14.38**	8.60

Depletion, depreciation and accretion expense for 2004 was $4.5 million or $14.38 per boe produced during the year. Depletion was high as a result of the capital costs to acquire Terraquest and the recording of associated asset retirement obligations of the acquired operations.

Masters performs an annual ceiling test in accordance with the Canadian Institute Chartered Accountants' full cost accounting guidelines, using forecasted prices determined by the independent qualified reserves evaluation firm that evaluates Masters reserves. Also, Masters performs a quarterly ceiling test at period end using adjusted prices received. At December 31, 2004, the impairment recognition portion of the ceiling test indicated the estimated undiscounted future cash flows from proved reserves exceeded the carrying values of producing petroleum and natural gas properties and, therefore, a ceiling test adjustment was not required.

TAXES

($ thousands, except as indicated)	***2004***	***2003***
Future income taxes (reduction)	**662**	(34)
Capital taxes	**-**	6
Total taxes (reduction)	**662**	(28)
Effective tax rate *(%)*	**60.7**	24.8

Future income tax expense of $0.7 million for the 2004 year is due to earnings for the period culminating from higher commodity prices and production volumes and a reduction in provincial income tax rates. Based on available tax pools, forecasted capital spending levels and commodity prices, Masters does not anticipate being taxable for the 2005 year.

Masters has approximately $31.9 million in tax pools to shelter taxable income in future years. Estimated 2004 tax pools are as follows.

($ thousands)	
Canadian Exploration Expense	5,473
Canadian Development Expense	2,917
Canadian Oil and Gas Property Expense	14,630
Undepreciated capital cost	6,039
Non-capital losses	1,580
Other	1,286
Total	31,925

NET EARNINGS (LOSS)

Net earnings after taxes for the year ended December 31, 2004 were $0.4 million or $0.03 per weighted average share outstanding as a result of higher commodity prices and production volumes.

MANAGEMENT'S DISCUSSION & ANALYSIS

Earnings ratios

($ thousands, except as indicated)	*2004*	*2003*
Net earnings (loss)	**428**	(110)
Earnings ratios *(%)*		
Return on capital [1]	**2.3**	(1.3)
Return on investment [2]	**2.0**	(0.4)
Return on shareholder equity [3]	**1.9**	(1.3)

(1) Net earnings (loss) plus after-tax financing charges on debt divided by average of opening and closing capital employed. Capital employed is a total of equity and bank debt.

(2) Net earnings (loss) plus after-tax financing charges on debt divided by average net investment. Net investment is total assets less current liabilities. Return on investment is calculated using the average opening and closing net investment.

(3) Net earnings (loss) are divided by average shareholders' equity.

Net earnings (loss) per boe

($/boe)	*2004*	*2003*
Total revenues (after hedge charges)	**37.69**	42.21
Royalties	**(6.79)**	(5.20)
Operating expenses	**(9.18)**	(8.13)
Net operating income	**21.72**	28.88
General and administrative (excluding stock-based compensation expense)	**(2.91)**	(42.30)
Interest expense	**(0.36)**	-
Cash flow from operations	**18.45**	(13.42)
Depletion, depreciation and accretion	**(14.38)**	(8.60)
Stock-based compensation	**(0.56)**	(8.28)
Future taxes	**(2.13)**	6.16
Net earnings (loss)	**1.38**	(24.14)

SHARE CAPITAL

The number of basic weighted average common shares outstanding, for the three month period ended December 31, 2004 was 14,363,647 (diluted - 14,613,521). For the year ended December 31, 2004, basic weighted average common shares outstanding were 13,521,707 (2003 - 3,812,834) and diluted average common shares outstanding were 13,716,226 (2003 - 3,812,834). Common shares issued and outstanding, as at December 31, 2004, were 14,363,647 (2003 - 8,876,000) after recording the effect of the reverse takeover and amalgamation of Terraquest on February 26, 2004. As of the date of this MD&A there was no change to the number of common shares issued and outstanding.

	2004	2003[1]
Outstanding common shares *(thousands)*		
Weighted average outstanding common shares		
Basic	**13,522**	3,813
Diluted	**13,716**	3,813
Outstanding securities at December 31		
Common shares	**14,364**	8,876
Common share options	**1,255**	575
Common share warrants	**1,000**	1,000
Diluted securities outstanding	**16,619**	10,451
($ thousands, except as indicated)		
Per share information		
Net earnings (loss)	**428**	(110)
Net earnings (loss) per share *($)*		
Basic	**0.03**	(0.03)
Diluted	**0.03**	(0.03)
Cash flow from operations	**5,634**	(67)
Cash flow from operations per share *($)*		
Basic	**0.42**	(0.02)
Diluted	**0.41**	(0.02)
Total asset book value	**37,291**	18,288
Total asset book value per share *($)* [2]		
Basic	**2.60**	2.06
Diluted	**2.24**	1.75
Book value (shareholders' equity) [2]	**27,570**	16,473
Book value per share *($)*		
Basic	**1.92**	1.86
Diluted	**1.66**	1.58
Proved plus probable reserves *(mboe)*	**2,834**	1,408
Reserves per 100 shares *(boe)* [2]		
Basic	**19.7**	15.9
Diluted	**17.1**	13.5

(1) For comparative purposes, 2003 share amounts take into account the consolidation of shares upon the amalgamation with Terraquest on February 2004.

(2) Calculated using outstanding common shares, options and warrants at year-end.

MANAGEMENT'S DISCUSSION & ANALYSIS

NET ASSET VALUE

Masters net asset value per share at December 31, 2004 increased by 45 percent to $2.80 per basic share compared to $1.93 per share in 2003 and, on a diluted basis, 34 percent to $2.80 per share in 2004 compared to $2.09 per share in 2003.

($ thousands, except as indicated)	***2004*** ***Constant price***	***2004*** ***Forecast price***[1]	***2003*** ***Forecast price***
Proved plus probable reserves value (10% discount before tax)	**32,013**	**36,127**	7,700
Undeveloped acreage [2]	**8,245**	**8,245**	48
Net working capital (debt)	**(4,116)**	**(4,116)**	9,389
Basic net asset value	**36,142**	**40,256**	17,137
Projected proceeds on exercise of options and warrants	**6,309**	**6,309**	4,700
Fully diluted net asset value	**42,451**	**46,565**	21,837
Common shares outstanding *(thousands)*			
Basic	**14,364**	**14,364**	8,876
Diluted	**16,619**	**16,619**	10,451
Net asset value per common share *($)*			
Basic [3]	**2.52**	**2.80**	1.93
Diluted [3]	**2.55**	**2.80**	2.09

(1) The 2004 reserves values are based on before-tax future cash flows as evaluated by the Company's independent qualified reserves evaluators, McDaniel & Associates Consultants Ltd., using their future commodity price forecast.
(2) Land values are determined using an estimated value of $100 per undeveloped acre.
(3) Calculated using outstanding common shares, options and warrants at year-end.

SHARE TRADING ACTIVITY

Masters common shares are listed and posted for trading on the Toronto Stock Exchange ("TSX") and trade under the symbol MSY. The following table summarizes monthly trading activity of Masters common shares for the year ended December 31, 2004.

Month	***Volume***	***High*** *($)*	***Low*** *($)*	***Close*** *($)*
January [1]	-	-	-	-
February [1]	-	-	-	-
March	219,800	3.25	2.45	2.55
April	299,200	2.69	2.20	2.50
May	319,100	2.48	2.20	2.30
June	250,100	2.45	2.00	2.40
July	306,300	2.49	2.25	2.45
August	165,700	2.65	2.40	2.54
September	437,600	2.77	2.46	2.70
October	1,472,100	2.80	2.56	2.65
November	1,003,600	2.85	2.58	2.65
December	382,500	2.69	2.30	2.60

(1) Masters common shares commenced trading on the TSX as of March 5, 2004.

CAPITAL EXPENDITURES

Total capital expenditures during 2004 were $30.5 million which included $10.9 million for exploration and development expenditures and $19.6 million for the acquisition and merger of Terraquest Energy Corporation on February 26, 2004. During 2003, all capital expenditures occurred in the last quarter of the year including $7.0 million for the acquisition of the Little Bow property in southern Alberta and $0.4 million on exploration and development activities. The 2004 exploration and development activity resulted in 19 wells (gross) drilled or recompleted and acquisition of 6,471 net acres of undeveloped land. Capital was spent primarily on exploration and development activities at various locations in southern and central Alberta.

($ thousands)	*2004*	*2003*
Land	**889**	109
Geological and geophysical	**620**	84
Drilling and completions	**6,652**	149
Equipping and facilities	**2,757**	-
Other	**2**	41
Total exploration and development capital	**10,920**	383
Producing property acquisition	**-**	7,010
Terraquest Energy Corporation	**19,584**	-
Total capital expenditures	**30,504**	7,393

UNDEVELOPED LAND HOLDINGS

Masters acquired approximately 84,000 undeveloped acres with the acquisition of Terraquest during 2004. The average working interest of the undeveloped lands held at December 31, 2004 was 52 percent. Planned drilling for 2005 will focus primarily on undeveloped lands held at 2004 year-end.

	2004		*2003*	
***Alberta** (acres)*	*Gross*	*Net*	*Gross*	*Net*
Southern	**28,813**	**20,432**	-	-
Central	**62,560**	**27,974**	1,600	480
Northern	**66,483**	**35,020**	-	-
Total undeveloped land	**157,856**	**83,426**	1,600	480

FINDING AND DEVELOPMENT COSTS

During 2004, Masters exploration and development program resulted in total proved reserves additions, after prior year revisions of 572,000 boe (588,000 boe on a proved plus probable basis) resulting in total exploration and development program finding and development costs of $19.09 per proved boe and $18.57 per proved plus probable boe. After including the change of future development capital, finding and development costs were $19.40 per proved boe and $19.06 per proved plus probable boe.

MANAGEMENT'S DISCUSSION & ANALYSIS

The combined 2003 and 2004 capital programs, including the acquisitions of Little Bow and Terraquest, resulted in finding and development costs $14.96 per proved boe and $12.05 per proved plus probable boe. Including the change in future development capital, finding and development costs were $15.03 per proved boe and $12.14 per proved plus probable boe.

Reserves disclosed for 2004 and 2003 conform with the requirements of National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities.

2004 Finding and development (F&D) and net acquisition (FD&A) costs

	Capital expenditures	Proved reserves additions	Proved costs	Proved plus probable reserves additions	Proved plus probable costs
	($ thousands)	(mboe)	($/boe)	(mboe)	($/boe)
F&D exploration and development before revisions	10,920	343	31.84	420	26.00
F&D exploration and development after revisions (a)	10,920	572	19.09	588	18.57
Change in proved future development capital (b)	178	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	288	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	11,098	572	19.40	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	11,208	n/a	n/a	588	19.06
Net acquisition activity (f)	19,584	840	23.31	1,149	17.04
Total 2004 FD&A costs before future development costs (a+f)	30,504	1,412	21.60	1,737	17.56
Total 2004 proved FD&A costs including future development costs (d+f)	30,682	1,412	21.73	n/a	n/a
Total 2004 proved plus probable FD&A costs including future development costs (e+f)	30,792	n/a	n/a	1,737	17.73

2003 Finding and development and net acquisition costs

	Capital expenditures ($ thousands)	Proved reserves additions (mboe)	Proved costs ($/boe)	Proved plus probable reserves additions (mboe)	Proved plus probable costs ($/boe)
F&D exploration and development before revisions	383	-	-	-	-
F&D exploration and development after revisions (a)	383	-	-	-	-
Change in proved future development capital (b)	n/a	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	n/a	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	383	-	-	-	-
Proved plus probable F&D including change in future development capital (e)=(a+c)	383	-	-	-	-
Net acquisition activity (f)	7,010	1,121	6.25	1,408	4.98
Total 2003 FD&A costs before future development costs (a+f)	7,393	1,121	6.60	1,408	5.25
Total 2003 proved FD&A costs including future development costs (d+f)	7,393	1,121	6.60	n/a	n/a
Total 2003 proved plus probable FD&A costs including future development costs (e+f)	7,393	n/a	n/a	1,408	5.25

MANAGEMENT'S DISCUSSION & ANALYSIS

Combined 2003 and 2004 finding and development and net acquisition costs

Masters Energy Inc. commenced operations December 22, 2003 with the acquisition of the Little Bow property in southern Alberta. The combined 2003 and 2004 results are more representative of management's efforts as illustrated in the table below.

	Capital expenditures	Proved reserves additions	Proved costs	Proved plus probable reserves additions	Proved plus probable costs
	($ thousands)	(mboe)	($/boe)	(mboe)	($/boe)
F&D exploration and development before revisions	11,303	343	32.95	420	26.91
F&D exploration and development after revisions (a)	11,303	572	19.76	588	19.22
Change in proved future development capital (b)	178	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)	288	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d)=(a+b)	11,481	572	20.07	n/a	n/a
Proved plus probable F&D including change in future development capital (e)=(a+c)	11,591	n/a	n/a	588	19.71
Net acquisition activity (f)	26,594	1,961	13.56	2,557	10.40
Total 2003 and 2004 FD&A costs before future development costs (a+f)	37,897	2,533	14.96	3,145	12.05
Total 2003 and 2004 proved FD&A costs including future development costs (d+f)	38,075	2,533	15.03	n/a	n/a
Total 2003 and 2004 proved plus probable FD&A costs including future development costs (e+f)	38,185	n/a	n/a	3,145	12.14

RESERVES REPLACEMENT

Masters 2004 exploration and development capital expenditure program replaced production by a factor of 1.8 on a proved basis and 1.9 on a proved plus probable basis.

	2004
Production *(mboe)*	311
Proved reserves additions after revisions *(mboe)*	572
Proved replacement ratio	1.84
Proved plus probable reserves additions after revisions *(mboe)*	588
Proved plus probable replacement ratio	1.89

MANAGEMENT'S DISCUSSION & ANALYSIS

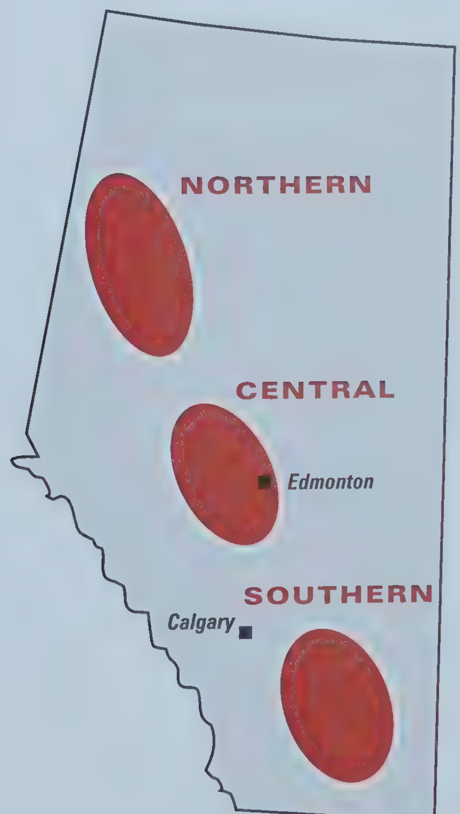
DRILLING RESULTS

During 2004, Masters drilled or recompleted 19 wells resulting in 10 natural gas wells for an overall success rate of 53 percent.

(wells)	*Gross*	*Net*
Natural gas	10	6.4
Dry and abandoned	9	6.6
Total	19	13.0
Success rate *(%)*	53	49

CORE AREA ACTIVITY

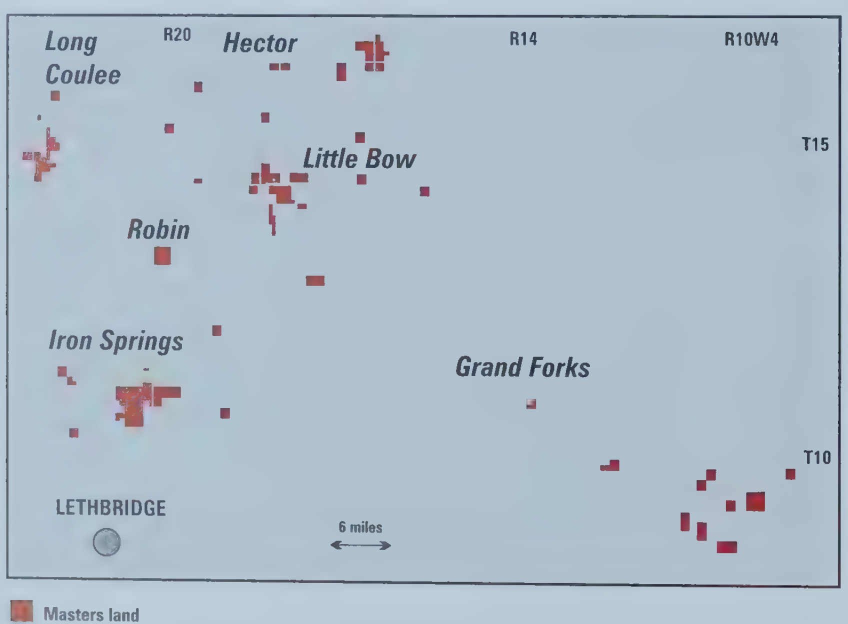
In 2005, Masters will continue to focus on exploiting opportunities within our core producing area at Little Bow and, at the same time, expand activities on our large undeveloped land base of 83,000 net acres in Alberta. For 2005, Masters anticipates spending $12 million on opportunities identified on existing corporate lands. We anticipate that numerous new prospects will be developed in addition to those currently identified. Masters strong balance sheet will allow the allocation of additional funding for new prospects where appropriate.



MANAGEMENT'S DISCUSSION & ANALYSIS

Southern Alberta

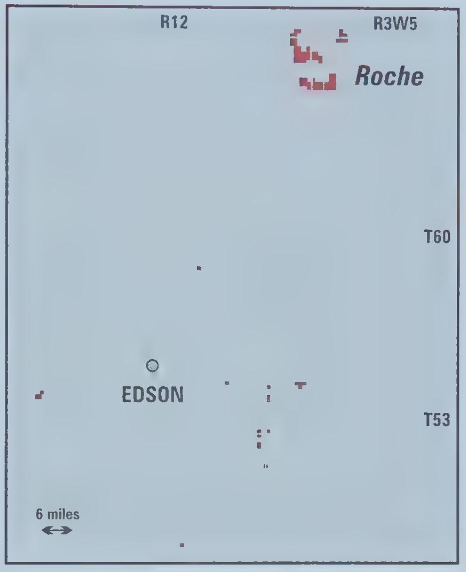
The 2003 acquisition of Little Bow provided an entry into southern Alberta for Masters. At the time of the acquisition the Little Bow property was producing approximately 450 boe/d. The Terraquest acquisition in February 2004 strategically enhanced our operations in southern Alberta with interests in producing properties at Little Bow, Long Coulee, Grand Forks, Hector and Badger. The Terraquest acquisition also provided 22,000 net acres of undeveloped lands for future drilling. During 2004, we drilled or recompleted seven wells (gross) resulting in six wells for an overall success rate of 86 percent. At Little Bow, we completed a 3D seismic survey on exploratory lands and an independent reservoir simulation study on the main producing pool. Based on recommendations of the study, plans for 2005 include drilling up to 14 additional infill wells and optimizing the existing waterflood to improve oil recovery. At Little Bow, 3D seismic surveys over exploratory lands have resulted in three defined locations. At Hector and Grand Forks we anticipate drilling several development wells. We will pursue additional exploration on, or in reasonable proximity to, existing Masters lands. Southern Alberta provided the majority of Masters 2004 production.



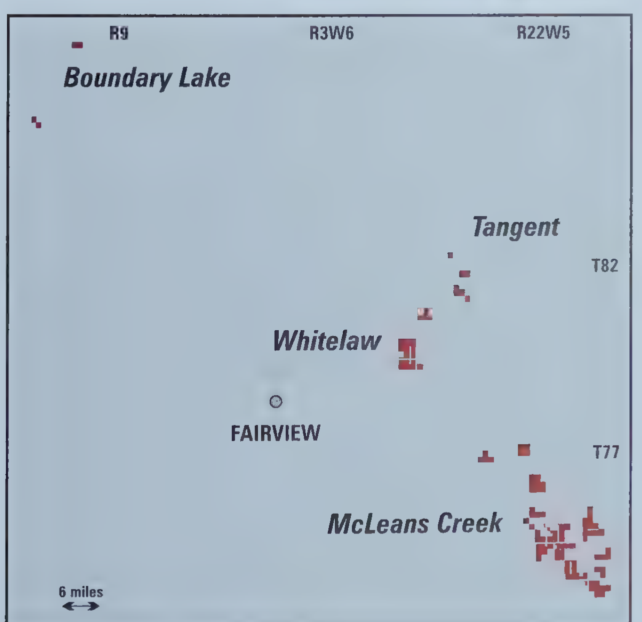
MANAGEMENT'S DISCUSSION & ANALYSIS

Central Alberta

The Terraquest acquisition provided 20,000 net acres of undeveloped exploratory lands in central Alberta. During 2004, we drilled or recompleted a total of eight exploratory wells resulting in three natural gas wells for a success rate of 38 percent. We plan to drill four wells at Roche in the first quarter of 2005 to follow up drilling success achieved in 2004. These drilling prospects will be pursuing natural gas in the Belly River and Lower Mannville zones.



Masters land



Northern Alberta

In conjunction with the Terraquest acquisition, Masters acquired 40,000 net undeveloped acres with an average working interest of 60 percent. Generally, the drilling prospects are multi-zone wells targeting the Montney, Gething, Cadimun, Charlie Lake, Bluesky and Dunvegan zones for oil and natural gas. During 2004, we drilled four exploration wells resulting in one natural gas well. In 2005, we have budgeted four to five medium depth, moderate risk wells in the area.

MANAGEMENT'S DISCUSSION & ANALYSIS

CONTRACTUAL OBLIGATIONS

Masters has contractual obligations on operating leases of field equipment and a demand revolving bank borrowing facility. Both are considered short term and due within one year, if demanded. As of December 31, 2004 Masters is not in breach of any debt covenant under the bank facility. Payments due within one year are as follows.

($ thousands)	
Bank debt	3,424
Operating leases	114
Total contractual obligations	3,538

LIQUIDITY AND CAPITAL RESOURCES

Total capitalization at December 31, 2004 was $44.5 million with the market value of common shares representing 84 percent of total capitalization. Net debt represented nine percent and asset retirement obligations and future income taxes accounted for seven percent.

Total market capitalization

($ thousands, except as indicated)	***2004***	*%*
Common shares outstanding *(thousands)*	**14,364**	
Share price, December 31, 2004 *($)*	**2.60**	
Total market capitalization	**37,346**	84
Working capital deficiency, excluding bank debt	**692**	
Bank debt	**3,424**	
Net debt	**4,116**	9
Asset retirement obligation	**3,044**	7
Future income taxes	**30**	-
Total capitalization	**44,536**	100
Net debt to total capitalization	**9%**	

At December 31, 2004, Masters had borrowed approximately $3.4 million and had a working capital deficit of $0.7 million totaling $4.1 million of total net debt. This net debt amount represents approximately 0.7 times 2004 cash flow from operations of $5.6 million and approximately 0.4 times budgeted 2005 cash flow from operations.

Masters has a bank demand revolving facility of $8.5 million to fund future activities. This is a borrowing base facility that is determined by the Company's latest reserves evaluation, results of operations, current and forecasted commodity prices and the prevailing market conditions. The facility is reviewed annually in May. As at December 31, 2004, Masters had drawn $3.4 million of the demand revolving facility and this amount is recorded as a current liability.

MANAGEMENT'S DISCUSSION & ANALYSIS

The capital intensive nature of our activities can create a negative working capital position in quarters with high levels of exploration and development capital spending. At December 31, 2004 the working capital deficiency, which includes $3.4 million of bank debt, is within Masters bank credit line. We continually manage our capital spending program by monitoring forecasted production, commodity prices and anticipated cash flow. Should circumstances arise to negatively affect cash flow, management is capable of reducing capital spending levels.

Our future investing activities, which consist primarily of capital expenditures on oil and gas activities, will be funded with working capital, cash flow from operations and a limited amount of bank debt.

Debt ratios

($ thousands, except as indicated)	***2004***
Working capital deficiency, excluding bank debt	692
Bank debt	3,424
Net debt	4,116
Debt to cash flow ratio	
Cash flow from operations	5,634
Net debt	4,116
Cash flow to repay net debt *(years)*	
2004 cash flow	0.73
Forward cash flow	0.38
Asset coverage ratio	
Total asset book value	37,291
Net debt	4,116
Asset coverage	9.06
Debt to equity ratio	
Net debt	4,116
Shareholders' equity	27,570
Debt to equity	0.15

OUTLOOK

The acquisitions of Terraquest and the Little Bow properties have created a strong production base from which Masters can grow. With an experienced technical team, a strong balance sheet, a large undeveloped land base (83,000 net acres) and a number of internally generated prospects, Masters is well positioned for growth. We expect to deliver production growth averaging 1,500 boe per day in 2005 from our internally generated exploration and development program. The Board of Directors has approved a $12 million capital program for 2005. Funds will be spent on developing existing internal opportunities, exploring new prospects and continuing to build an inventory of exploration and development opportunities that will provide growth in 2006 and beyond.

In addition to the ongoing exploration and development program, Masters will grow through acquisitions and continues to seek opportunities that are strategic and add future value. Our strong balance sheet allows ample flexibility to complete potential acquisitions which could be material.

MANAGEMENT'S DISCUSSION & ANALYSIS

2005 Capital budget

In Masters initial year of operations, we allocated our capital to exploring and developing opportunities in our core areas of southern, central and northern Alberta. Through the efforts of this program, we established a large inventory of future drilling opportunities. For 2005, we will drill approximately 25 wells in our current areas of focus and will operate a majority of the prospects identified for drilling.

Based on forecasted average production of 1,500 boe per day, commodity prices of $35.00 (US) per bbl for WTI crude and a natural gas spot wellhead price of $6.50 per mcf, the US to Canadian foreign exchange of $0.80 (US) and costs remaining at historical levels, 2005 cash flow is anticipated to be approximately $11 million.

Masters 2005 capital program is forecast to be $12 million with an approximate allocation of $2.3 million for land and seismic, $6.9 million for drilling and completions and $1.5 million for facilities. Net debt at December 31, 2004 was $4.1 million and is forecast to be approximately $5.0 million at the 2005 year-end.

2005 Sensitivities

Based on forecasted assumptions, the following sensitivities are provided to indicate the impact on cash flow and earnings for changes in commodity prices and the Canadian currency.

($ thousands)	***Cash flow from operations***	***Earnings***
Impact on 2005		
Change in WTI oil price of $1.00 (US) per bbl	345	224
Change in natural gas price of $0.10 (Cdn) per mcf	104	72
Change in US dollar to Cdn dollar of $0.01 (US)	148	96

MANAGEMENT'S DISCUSSION & ANALYSIS

SELECTED QUARTERLY INFORMATION

Masters prepared the financial data presented below in accordance with Canadian generally accepted accounting principles. The reporting and measurement currency is the Canadian dollar. Masters commenced oil and gas operations after acquiring the Little Bow property on December 22, 2003.

	2004				*2003*
Operations	***Q4***	***Q3***	***Q2***	***Q1***	***Q4***
Production					
Oil *(bbls/d)*	588	597	556	488	426
NGL *(bbls/d)*	13	5	9	2	1
Natural gas *(mcf/d)*	2,406	1,980	1,653	800	171
Equivalent *(boe/d)*	1,002	932	841	619	455
Pricing					
Oil, before hedging *($/bbl)*	36.91	42.40	37.10	33.60	27.72
Hedging costs	(0.01)	(4.25)	-	-	-
Oil, after hedging *($/bbl)*	36.90	38.15	37.10	33.60	27.72
NGL *($/bbl)*	50.72	40.20	36.86	45.11	43.34
Natural gas *($/mcf)*	6.62	6.24	6.51	7.35	7.19
Equivalent *($/boe)*	38.09	37.90	37.95	35.82	28.70
Financial					
($ thousands, except as indicated)					
Total revenue	3,501	3,258	2,922	2,028	192
Cash flow from operations	1,675	1,513	1,391	1,055	(67)
Net earnings (loss)	(124)	79	(49)	522	(110)
Basic per share *($)*	(0.01)	0.01	-	0.05	(0.03)
Diluted per share *($)*	(0.01)	0.01	-	0.05	(0.03)
Capital spending					
Exploration and development	3,240	2,531	2,761	2,388	383
Acquisitions	-	-	-	20,174	7,010
Total assets	37,291	35,518	34,833	34,271	18,288
Working capital deficiency (surplus)	4,116	2,551	1,533	163	(9,390)
Long-term debt	-	-	-	-	-
Shareholders' equity *(thousands)*	27,570	27,639	27,504	27,508	16,473
Weighted average common shares outstanding *(thousands)*					
Basic	14,364	14,364	14,364	10,987	3,813
Diluted	14,614	14,553	14,505	11,184	3,813

Factors that caused variations over the quarters are outlined below.

- Since an initial financing in the fourth quarter of 2003, Masters has completed two acquisitions which have impacted production growth.

  - The acquisition of the Little Bow property in southern Alberta on December 22, 2003 added approximately 450 boe/d consisting of approximately 90 percent crude oil production. Proved and probable reserves acquired were approximately 1.4 mmboe with an estimated reserves life index of 8.6 years.

  - The acquisition of Terraquest Energy Corporation on February 26, 2004 added production of approximately 400 boe/d consisting of approximately 60 percent natural gas. Proved and probable reserves acquired were approximately 1.1 mmboe with an estimated reserves life index of 7.9 years based on the production at the time of acquisition.

- Production subsequent to the acquisitions is a result of Masters exploration and development activities. Commencement of production is subject to the timing of drilling and facility construction activities.

- Growth in revenue and cash flow is due to the combination of increased production and strong commodity prices. Generally, commodity prices were consistently elevated throughout 2004 with WTI light quality crude averaging $41.42 (US) per bbl and the AECO natural gas spot price of $6.87 per mcf. Oil prices for medium grade quality crude experienced a large drop in the latter portion of the fourth quarter 2004 due to wider than historical quality differentials. This impacted prices received by Masters during the fourth quarter of 2004 as the majority of our crude production is medium quality.

- Net earnings are influenced by depletion, depreciation, accretion and future income taxes. Masters internally estimates its reserves every quarter based on acquisition and drilling activities. Independent qualified reserves evaluation engineers determine annual reserves and this can affect fourth quarter reserves additions. Enacted changes to federal and provincial income tax rates for the oil and gas industry will impact future income taxes.

- Capital spending increased over the year with the development of future drilling prospects. Capital spending was funded through cash flow and bank debt.

FOURTH QUARTER ANALYSIS

	Q4 2004	*Q3 2004*	*Q4 2003*	*% Change Q4 2004 vs Q3 2004*	*% Change Q4 2004 vs Q4 2003*
Operations results					
Production					
Crude oil *(bbls/d)*	**588**	**597**	426	(2)	38
NGL *(bbls/d)*	**13**	**5**	1	160	1,200
Natural gas *(mcf/d)*	**2,406**	**1,980**	171	21	1,307
Equivalent *(boe/d)*	**1,002**	**932**	455	8	120
Pricing (after hedging)					
Crude oil *($/bbl)*	**36.90**	**38.15**	27.72	(3)	33
NGL *($/bbl)*	**50.72**	**40.20**	43.34	26	17
Natural gas *($/mcf)*	**6.62**	**6.24**	7.19	6	(8)
Selected financial results					
($ thousands, except as indicated)					
Total revenue	**3,501**	**3,258**	192	7	1,723
Royalties	**(647)**	**(595)**	(24)	9	2,596
Operating expense	**(809)**	**(889)**	(37)	(9)	2,086
General and administrative	**(334)**	**(266)**	(230)	26	45
Cash flow from operations	**1,675**	**1,513**	(67)	11	2,601
Depletion, depreciation and accretion	**1,309**	**1,275**	39	3	3,256
Net earnings (loss)	**(124)**	**79**	(110)	(257)	(13)
Basic per share *($)*	**(0.01)**	**0.01**	(0.03)	(200)	67
Diluted per share *($)*	**(0.01)**	**0.01**	(0.03)	(200)	67
Capital spending					
Exploration and development	**3,240**	**2,531**	383	28	746
Acquisitions	**-**	**-**	7,010	-	(100)
Total capital spending	**3,240**	**2,531**	7,393	28	(56)
Working capital deficiency (surplus)	**4,116**	**2,551**	(9,390)	61	144
Shareholders' equity	**27,570**	**27,639**	16,473	-	67
Weighted average common shares outstanding *(thousands)*					-
Basic	**14,364**	**14,364**	3,813	-	276
Diluted	**14,614**	**14,553**	3,813	1	283

PRODUCTION

Production volumes from the Terraquest properties have been included in Masters 2004 results from the date of amalgamation on February 26, 2004. Production volumes for the fourth quarter were 1,002 boe/d with a production mix of 60 percent oil and NGL and the balance, natural gas. Production for the fourth quarter 2004 increased eight percent compared to the third quarter and 120 percent compared to the fourth quarter of 2003. This production increase is a result of drilling activity in the third quarter and the acquisition of Terraquest in February 2004.

REVENUES

Oil and natural gas revenues for the fourth quarter 2004 totaled $3.5 million, up seven percent from the third quarter as commodity prices remained strong and production volumes continued to increase. Revenues for the fourth quarter of 2003 are reported from the date of acquiring the Little Bow property on December 22, 2003 until year-end.

ROYALTIES

Royalties for the fourth quarter of 2004 increased nine percent to $0.6 million over the third quarter 2004. Our average royalty rate relative to resource revenues has remained constant at 18 percent for 2004 and 2003. The majority of royalty expense incurred during the quarter was payable to the crown. Royalties for the fourth quarter 2004 were $7.02 per boe in comparison to $6.94 per boe for the third quarter 2004 and $5.20 per boe for the fourth quarter of 2003.

OPERATING EXPENSES

Operating expenses for the fourth quarter of December 31, 2004 decreased nine percent to $0.8 million from the third quarter 2004 expense of $0.9 million. Operating expenses for the fourth quarter averaged $8.78 per boe compared to an average cost of $10.38 per boe for the third quarter 2004 and $8.13 per boe for the fourth quarter of 2003. Operating expenses were higher than anticipated in the third quarter of 2004 due to well servicing, plant turnaround and annual maintenance activities carried out during the summer. During 2005, we anticipate that operating costs will average approximately $8.50 per boe.

GENERAL AND ADMINISTRATIVE

Fourth quarter 2004 net G&A expense increased 26 percent to $0.3 million from the third quarter of 2004 and 45 percent from the fourth quarter of 2003. General and administrative expenses averaged $3.62 per boe for the fourth quarter compared to $3.10 per boe in the third quarter of 2004 and $50.58 per boe in the fourth quarter 2003. The 2004 fourth quarter general and administrative expenses include annual provisions for the annual audit and reserves reports. G&A for 2005, including a non-cash provision for future stock-based compensation of approximately $0.2 million, is forecast to be approximately $2.10 per boe.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion expense for the fourth quarter of 2004 was $1.3 million compared to $1.3 million for the third quarter of 2003 and $39,000 for the fourth quarter 2003. Depletion, depreciation and accretion provision for the fourth quarter was $14.27 per boe compared to $14.88 per boe in the third quarter of 2004 and $8.60 per boe for the fourth quarter of 2003. The depletion rate per boe for the fourth quarter of 2004 was lower due to year-end adjustments for reserves. The increase in the depletion rate since the fourth quarter of 2003 was due to the acquisition of Terraquest in February 2004 and our exploration and development activities throughout 2004.

MANAGEMENT'S DISCUSSION & ANALYSIS

TAXES

The future income tax provision for the fourth quarter of 2004 was $0.5 million compared to $0.1 million for the third quarter of 2004 and a combined future income tax and capital tax reduction of $28,000 for the fourth quarter of 2003. The provision for the 2004 fourth quarter increased as result of matching future forecasted cash flows, determined by the independent qualified reserves evaluation engineers, to the changes in corporate federal income tax rates over the next few years.

NET EARNINGS

Net loss after future taxes for the fourth quarter of 2004 was $0.1 million compared to earnings of $0.1 million for the third quarter of 2004 and a loss of $0.1 million during the fourth quarter of 2003. The change in net earnings is mainly due to higher production, commodity prices and future income taxes.

CAPITAL EXPENDITURES

During the fourth quarter of 2004, Masters spent $3.2 million on exploration and development capital including $0.5 in land, $0.3 million in seismic, $1.8 million in drilling and completions and $0.7 million in facilities. During the quarter we drilled four wells resulting in one gas well, acquired 2,920 (1,351 net) acres of undeveloped land, and, at the Little Bow property, completed an independent reservoir simulation study and shot a 3D seismic program over exploration acreage.

Capital spending during the fourth quarter was $3.2 million compared to $2.5 million in the third quarter of 2004 and $7.4 million in the fourth quarter of 2003. During the fourth quarter of 2003, Masters acquired the Little Bow property for $7.0 million.

CRITICAL ACCOUNTING ESTIMATES

1. Depletion and depreciation expense of petroleum and natural gas properties
Masters follows the full cost method of accounting whereby all costs related to the exploration for and the development of petroleum and natural gas reserves are initially capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and lease and well equipment. Costs capitalized are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified evaluation engineers. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The costs of significant unproved properties are excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties or impairment has occurred.

Masters performs a ceiling test for impairment for each cost centre in a two-stage test undertaken at least annually.

MANAGEMENT'S DISCUSSION & ANALYSIS

Impairment is recognized if the carrying value of the petroleum and natural gas properties, less accumulated depletion and depreciation, exceeds the estimated future cash flows from proved oil and natural gas reserves, on an undiscounted basis, using forecast prices and costs and the lower of cost and fair value of unproven properties. Future cash flows are calculated before interest, general and administrative expenses and income taxes.

If impairment is indicated by applying the calculations described in (i) above, the Company will measure the amount of the impairment by comparing the carrying value of the petroleum and natural gas properties less accumulated depletion and depreciation to the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at a risk-free rate of interest, using forecast prices and costs and the lower of cost and fair value of unproven properties. Any impairment recognized is recorded as additional depletion and depreciation expense.

The amounts recorded for depletion and depreciation of oil and gas properties, and the ceiling test, are based on estimates. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

2. Asset retirement obligation

Masters recognizes the liability for asset retirement obligations associated with the abandonment of oil and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's credit-adjusted risk-free interest rate. The future costs are estimates that are subject to measurement uncertainty and any change would impact the liability.

3. Stock-based compensation

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income effect are based on estimates of the future volatility of the Company's share price, expected lives of the options, expected dividends and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

4. Income taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

5. Business combinations

Business combinations are accounted for using the purchase method of accounting. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value involves many assumptions. The valuation of acquired oil and gas properties is based on the discounted proved plus probable reserves as determined by an independent reserves evaluation using future commodity prices and costs. Masters staff internally estimate undeveloped resource property values.

CHANGE IN ACCOUNTING POLICY

Effective January 1, 2004, and, consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation costs have been reclassified as an expense in the statement of earnings and retained earnings. Previously, Masters followed standard industry practice and deducted transportation costs from petroleum and natural gas revenue.

BUSINESS RISKS AND UNCERTAINTIES

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector.

Masters is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Masters business has inherent risk and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include market fluctuations in commodity prices, interest rates and currency exchange rates. Operational risks include industry competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The exploration for, and production of, oil and gas requires manpower and capital. Masters employs highly qualified and experienced staff, who have demonstrated their ability to generate quality drilling prospects utilizing the latest technological tools to increase the probability of success. The drilling of a successful well is enhanced because we explore in core areas that have multi-zone potential, focusing on low to moderate-risk prospects with a limited exposure to high-risk, high-reward opportunities. Masters maintains operational control on a majority of prospects, and thus controls timing, assignment of resources and capital invested in exploration and development opportunities.

Commodity prices are influenced by a wide number of factors beyond Masters control. To manage this risk, we concentrate in regions which permit multiple delivery points to markets and enter into fixed price commodity contracts, on a limited portion of production, within our self-imposed hedging guidelines.

The acquisition of undeveloped mineral leases, supply of services and production equipment at competitive prices is essential to our ability to add reserves at a competitive cost and to produce these reserves in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult and expensive to obtain. Increased prices for supplies and services can inflate costs of operations and potentially erode product netbacks. Masters attempts to mitigate this risk by developing strong long-term relationships with industry participants, suppliers and contractors.

There are potential risks to the environment inherent to Masters business activities. To mitigate these risks, Masters conducts all operations at high standards and follows safety procedures designed to protect and maintain the environment as well as public and employee safety on behalf of shareholders, staff and other stakeholders at large. Masters minimizes environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and carrying adequate insurance coverage.

ADDITIONAL INFORMATION

Additional information relating to the Masters, including the Annual Information Form (AIF) is filed on SEDAR and can be viewed at www.sedar.com. Copies of the AIF can also be obtained by contacting Masters Energy Inc. at 520, 736 - 6th Avenue SW Calgary, Alberta, Canada T2P 3T7 or by email at boyd@mastersenergy.com. This information is also accessible on the Masters website at www.mastersenergy.com.

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (NI 51-101 F3)

Management of Masters Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and
(ii) The related estimated future net revenue; and

(b) (i) Proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and
(ii) The related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of the Company has

(c) Reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(d) Met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(e) Reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(f) The content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(g) The filing of the report of the independent qualified reserves evaluator on the reserves data; and

(h) The content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Geoffrey C. Merritt
President and Chief Executive Officer

Randall P. Boyd
Chief Financial Officer

Fred C Coles

Fred Coles
Director and Chair of the Reserves Committee
March 3, 2005

Kerry D. Lyons
Director and Member of the Reserves Committee

MANAGEMENT'S DISCUSSION & ANALYSIS

REPORT OF INDEPENDENT QUALIFIED RESERVES EVALUATORS (NI 51-101 F2)

To the Board of Directors of Masters Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

   (a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

   (ii) The related estimated future net revenue; and

   (b) (i) Proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

   (ii) The related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors.

			Net present value of future net revenue *(before income taxes, 10% discount rate)* *($ thousands)*			
Independent qualified reserves evaluator or auditor	***Preparation date of evaluation report***	***Location of reserves (country or foreign geographic area)***	***Audited***	***Evaluated***	***Reviewed***	***Total***
McDaniel & Associates Consultants Ltd.	Dec 31, 2004	Canada	$nil	$36,127	$nil	$36,127

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Phil Welch

P. A. Welch
McDaniel & Associates Consultants Ltd.
Calgary, Alberta
February 18, 2005

MANAGEMENT'S DISCUSSION & ANALYSIS

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION (NI 51-101 F1)

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated February 18, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is January 25, 2005.

Background

Masters Energy Inc. was incorporated under the Alberta Business Corporations Act on August 28, 2003. During the fall of 2003 Masters completed a private placement of 17,752,000 special warrants for gross proceeds of $17.8 million. On December 22, 2003 Masters acquired producing oil and gas properties in the Little Bow area of southern Alberta for $7.0 million.

On February 26, 2004, Masters and Terraquest Energy Corporation ("Terraquest"), a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco Common Share for every 12 common shares of Terraquest and Masters shareholders receive one Amalco Common Share for every two common shares of Masters. After giving effect to the transaction, Amalco had approximately 14.36 million common shares outstanding.

The consequence of the reverse take-over and amalgamation of Terraquest on February 26, 2004 was the loss of any relevant comparative analysis for Masters in the 2003 year.

The Company's head and registered office is located at Suite 520, 736 - 6th Avenue S.W., Calgary, Alberta, T2P 3T7.

Unless the context otherwise requires, "Masters" or the "Company" means Masters Energy Inc.

Masters shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MSY".

Disclosure of reserves data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by McDaniel & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2004 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Company's reserves are in Canada and, specifically, in the province of Alberta.

MANAGEMENT'S DISCUSSION & ANALYSIS

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of the Company's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves data - constant prices and costs

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2004
Constant prices and costs

	Reserves							
Reserves category	***Light and medium oil***		***Natural gas liquids***		***Natural gas***		***Total***	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(mbbls)	*(mbbls)*	*(mbbls)*	*(mbbls)*	*(mmcf)*	*(mboe)*	*(mboe)*	*(mboe)*
Proved								
Developed Producing	1,318	1,205	12	8	3,252	2,439	1,872	1,620
Developed non-producing	40	34	12	8	1,627	1,158	323	235
Undeveloped	-	-	-	-	-	-	-	-
Total proved	1,358	1,239	24	16	4,879	3,597	2,195	1,854
Probable	336	306	8	5	1,573	1,151	607	503
Total proved plus probable	1,695	1,545	32	21	6,452	4,748	2,802	2,357

	Net present values of future net revenue									
Reserves category	***Before income taxes discounted at percent per year***					***After income taxes discounted at percent per year***				
	0	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**
($ millions)										
Proved										
Developed producing	26.4	22.8	20.0	17.9	16.2	26.1	22.5	19.8	17.7	16.1
Developed non-producing	7.4	6.5	5.8	5.3	4.8	4.9	4.4	4.0	3.6	3.3
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total proved	33.8	29.3	25.8	23.1	21.0	31.0	26.9	23.8	21.3	19.4
Probable	10.9	8.0	6.2	4.9	4.1	7.9	5.6	4.3	3.4	2.8
Total proved plus probable	44.7	37.3	32.0	28.1	25.1	38.9	32.5	28.0	24.7	22.2

MANAGEMENT'S DISCUSSION & ANALYSIS

Total future net revenue (undiscounted)
As of December 31, 2004
Constant prices and costs

Reserves category	Revenue	Royalties less ARTC	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
($ thousands)								
Proved reserves	70,021	10,679	22,788	508	2,249	33,798	2,806	30,992
Proved plus probable reserves	89,934	13,919	28,341	683	2,524	44,743	5,883	38,860

Future net revenue by production group
As of December 31, 2004
Constant prices and costs

Reserves category	Production group	Future net revenue before income taxes (discounted at 10 percent per year)
($ thousands)		
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	9,721
	Natural gas (including by-products but excluding solution gas from oil wells)	14,611
	Other revenue/costs	1,516
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	11,621
	Natural gas (including by-products but excluding solution gas from oil wells)	18,523
	Other revenue/costs	1,869

MANAGEMENT'S DISCUSSION & ANALYSIS

Reserves data - forecast prices and costs

Summary of oil and gas reserves and net present values of future net revenue
As of December 31, 2004
Forecast prices and costs

Reserves category	Reserves: Light and medium oil Gross (mbbls)	Net (mbbls)	Natural gas liquids Gross (mbbls)	Net (mbbls)	Natural gas Gross (mmcf)	Net (mboe)	Total Gross (mboe)	Net (mboe)
Proved								
Developed	1,342	1,236	12	8	3,261	2,445	1,898	1,652
Producing								
Developed non-producing	41	34	12	8	1,630	1,160	325	235
Undeveloped	-	-	-	-	-	-	-	-
Total proved	1,383	1,270	24	16	4,892	3,605	2,222	1,887
Probable	342	314	8	5	1,571	1,150	611	512
Total proved plus probable	1,725	1,585	32	21	6,463	4,755	2,834	2,399

Reserves category ($ millions)	Net present values of future net revenue: Before income taxes discounted at percent per year: 0	5	10	15	20	After income taxes discounted at percent per year: 0	5	10	15	20
Proved										
Developed producing	32.2	28.8	24.5	21.9	19.9	30.0	26.0	23.0	20.7	18.8
Developed non-producing	6.7	5.9	5.3	4.8	4.4	4.4	3.9	3.5	3.2	2.9
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total proved	38.9	33.7	29.8	26.7	24.3	34.4	30.0	26.5	23.8	21.7
Probable	11.9	8.4	6.3	5.0	4.1	8.5	5.9	4.3	3.4	2.7
Total proved plus probable	50.7	42.2	36.1	31.7	28.4	42.9	35.8	30.9	27.2	24.5

Total future net revenue (undiscounted)
As of December 31, 2004
Forecast prices and costs

Reserves category ($ thousands)	Revenue	Royalties less ARTC	Operating costs	Development costs	Well abandonment costs	Future net revenue before income taxes	Income taxes	Future net revenue after income taxes
Proved reserves	80,087	11,198	26,617	523	2m883	38,865	4,424	34,441
Proved plus probable reserves	102,774	14,401	33,975	711	2,939	50,746	7,855	42,891

MANAGEMENT'S DISCUSSION & ANALYSIS

Future net revenue by production group
As of December 31, 2004
Forecast prices and costs

Reserves category	***Production group***	***Future net revenue before income taxes (discounted at 10 percent per year)***
($ thousands)		
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	14,892
	Natural gas (including by-products but excluding solution gas from oil wells)	13,429
	Other revenue/costs	1,482
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	17,478
	Natural gas (including by-products but excluding solution gas from oil wells)	16,844
	Other revenue/costs	1,806

Notes to reserves data tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   Reserve categories
   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions.

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

MANAGEMENT'S DISCUSSION & ANALYSIS

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

(c) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of certainty for reported reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast prices and costs

Forecast prices and costs are those:

(a) Generally acceptable as being a reasonable outlook of the future; and

(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at January 1, 2005, inflation and exchange rates utilized by McDaniel in the McDaniel Report (which were McDaniel's then current forecast at the date of the McDaniel Report) were as follows:

Summary of pricing and inflation rate assumptions
As of December 31, 2004
Forecast prices and costs

	Oil [1]						
Year	**WTI Cushing Oklahoma**	**Edmonton par price 40° API**	**Bow River medium 25° API**	**Natural gas AECO price**	**Edmonton Natural gas liquids mix**	**Inflation rates [1]**	**Exchange rate [2]**
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/bbl)*	*($Cdn/GJ)*	*($Cdn/bbl)*	*(%/year)*	*($US/$Cdn)*
Forecast							
2005	42.00	49.60	37.00	6.45	37.20	2	0.83
2006	39.50	46.60	37.10	6.20	35.10	2	0.83
2007	37.00	43.50	34.60	6.05	33.00	2	0.83
2008	35.00	41.10	32.70	5.80	31.20	2	0.83
2009	34.50	40.50	32.20	5.70	30.80	2	0.83
2010	34.30	40.20	32.00	5.60	30.50	2	0.83
Thereafter	+ 2%/yr	+ 2%/yr	+ 2%/yr	+ 2%/yr	+ 2%/yr	+ 2%/yr	0.83

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized, before hedge costs, by the Company for the year ended December 31, 2004, were $6.59 per mcf for natural gas, $37.66 per bbl for crude oil and $44.25 per bbl for natural gas liquids.

4. Constant prices and costs

Constant prices and costs are:

(a) The Company's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Company's prices are the posted prices for crude oil and the spot price for natural gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the McDaniel Report were as follows.

Summary of pricing assumptions
As of December 31, 2004
Constant prices and costs

	Oil					
Year	**WTI Cushing Oklahoma**	**Edmonton par price 40° API**	**Bow River medium 25° API**	**Natural gas Alberta average price**	**Edmonton Natural gas liquids mix**	**Exchange rate[1]**
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/bbl)*	*($Cdn/GJ)*	*($Cdn/bbl)*	*($US/$Cdn)*
Historical [2]						
2005+	43.45	46.51	25.03	6.62	35.30	0.8319

Notes:
(1) The exchange rate as at December 31, 2004.
(2) As at December 31.

5. Future development costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserves categories noted below.

	Forecast prices and costs				Constant prices and costs	
	Proved reserves		Proved plus probable reserves		Proved reserves	
	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities	Drilling & comp	Equip & facilities
($ thousands)						
2005	-	479	51	479	-	470
2006	-	-	-	-	-	-
2007	-	-	-	-	-	-
2008	-	-	54	-	-	-
2009	-	-	83	-	-	-
Thereafter	44	-	44	-	38	-
Total undiscounted	44	479	232	479	38	470
Total discounted at 10%	22	457	159	457	19	448

In all the years of the economic forecasts, the net revenues from the reserves are well in excess of the estimated future development costs. Therefore the Company can meet the funding requirements for future development entirely out of its cash flow and no other source of funding is required to develop the proved or the proved plus probable reserves.

6. The ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995.

7. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.

8. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

9. The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliations of changes in reserves and future net revenue

Reconciliation of company gross reserves by principal product type
Forecast prices and costs

	Light and medium oil			Natural gas liquids			Associated and non-associated gas		
	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable	Proved	Probable	Proved plus probable
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mmcf)
Dec. 31, 2003	1,027	262	1,289	-	1	1	561	145	706
Extensions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	216	(39)	177	(28)	1	(27)	252	(133)	139
Discoveries	15	3	18	39	-	39	1,734	438	2,172
Acquisitions	330	116	446	16	6	18	2,970	1,121	4,091
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	
Production	(204)	-	(204)	(3)	-	(3)	(625)	-	(625)
Dec. 31, 2004	1,383	342	1,725	24	8	32	4,892	1,571	6,463

Reconciliation of changes in net present values of future net revenue after tax
Discounted at 10 percent per year
Proved reserves
Constant prices and costs

Period and factor	2005
($ millions)	
Estimated future net revenue at beginning of year	6.8
Sales and transfers of oil and gas produced, net of production costs and royalties	(6.9)
Net change in prices, production costs and royalties related to future production	(0.8)
Changes in previously estimated development costs incurred during the period	-
Changes in estimated future development costs	0.2
Extensions and improved recovery	3.9
Discoveries	5.8
Acquisitions of reserves	13.6
Dispositions of reserves	-
Accretion of discount	0.7
Net change in income taxes	0.5
Estimated future net revenue at end of year	23.8

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped reserves

Proved undeveloped reserves

Proved undeveloped reserves are within the following categories:

- Wells budgeted and scheduled to be drilled in 2005.

- Gas caps that will be blown down once the oil has been depleted.

- Secondary zones that will be brought on production once the primary zone has been depleted.

The Company does not carry any proved undeveloped reserves.

Probable undeveloped reserves

The Company does not carry probable undeveloped reserves.

Significant factors or uncertainties

Estimates of economically recoverable oil and natural gas reserves (including NGL) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from the actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

MANAGEMENT'S DISCUSSION & ANALYSIS

OTHER OIL AND GAS INFORMATION

Principal properties

The following is a description of Masters oil and natural gas properties as at December 31, 2004. Production stated is net to Masters. Reserves amounts are stated, before deduction of royalties, at December 31, 2004 based on forecast costs and prices as evaluated in the McDaniel Report (see "Reserves Data"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004.

Little Bow, Alberta

Masters purchased the Little Bow property on December 22, 2003. Little Bow is located 50 miles north of Lethbridge, Alberta. Masters has an average working interest of 66 percent in 4,520 (2,986 net) acres of developed land and an average 69 percent working interest in 3,120 (2,156 net) acres of undeveloped lands. As at December 31, 2004, 22 wells were producing. Masters operated the majority of these wells.

During 2004 an independent reservoir simulation study was conducted on the Glauconite pool and concluded that further infill drilling and waterflood optimization is required to enhance the recovery of hydrocarbons. A 3D seismic program was conducted on the western exploration lands held in the area. In addition, two existing wells were successfully re-entered in the Bow Island zone. The area offers multi-zone oil and gas potential at shallow depths. For 2005, plans are to drill up to 14 wells, the majority of which will be infill wells recommended by the reservoir simulation study.

Total proved reserves were estimated by McDaniel to be 1,195 mbbls of crude oil and 1,183 mmcf of natural gas as at December 31, 2004. Production averaged 467 bbls/d of crude oil and NGL and 201 mcf/d of natural gas for the year ended December 31, 2004.

Badger, Alberta

The Badger area is located 60 miles north of Lethbridge, Alberta. Masters has an average working interest of 28.95 percent in 2,560 acres of developed land and three (0.6 net) producing wells in the area.

A Glauconite natural gas well (0.3 net) drilled in 2003 commenced production in April 2004.

Total proved reserves were estimated by McDaniel to be 3.1 mbbls of NGL and 866 mmcf of natural gas as at December 31, 2004. Production averaged 2 bbls/d of NGL and 359 mcf/d of natural gas for the year ended December 31, 2004.

MANAGEMENT'S DISCUSSION & ANALYSIS

Roche, Alberta

Masters holds working interests of 33 to 50 percent in 75 sections of undeveloped land and 640 (315 net) acres of developed land in the Roche area, 30 miles northeast of Swan Hills.

A number of drilling locations have been identified for Lower Mannville or Belly River potential and drilling of the first three wells occurred in February 2004 resulting in one natural gas well. Production commenced in the latter half of March 2004. Masters has scheduled four wells for drilling during the 2005 winter season.

Total proved reserves were estimated by McDaniel to be 99 mmcf of natural gas as at December 31, 2004. Production averaged 55 mcf/d of natural gas for the year ended December 31, 2004.

Eyremore, Alberta

The Eyremore area is located approximately 30 miles east of the town of Vulcan. Masters has a 100 percent working interest in 4,320 acres of undeveloped land in this area.

The primary exploration target in this area is the Ostracod zone, at depths of 1,200 metres, with secondary targets in the Upper and Lower Mannville zones. During 2004 one natural gas well was drilled and brought onstream in November 2004 at 1.2 mmcf/d. Seven additional drilling locations have been identified and will potentially be drilled during 2005.

Total proved reserves in this area were estimated by McDaniel in the McDaniel Report to be 792 mmcf of natural gas and 2,370 bbls of NGL at December 31, 2004.

Production from the Eyremore area averaged 279 mcf/d of natural gas and 2 bbls/d of crude oil and NGL for the year ended December 31, 2004.

Iron Springs, Alberta

The Iron Springs area is located approximately 10 miles north of the city of Lethbridge. Masters has an average working interest of 92 percent in 12,440 (11,420 net) acres of land and six (6.0 net) producing natural gas wells and one (1.0 net) cased natural gas well in this area.

Total proved natural gas reserves in this area were estimated by McDaniel in the McDaniel Report to be 296 mmcf at December 31, 2004.

Production from the Iron Springs area averaged 412 mcf/d of natural gas for the year ended December 31, 2004.

MANAGEMENT'S DISCUSSION & ANALYSIS

Long Coulee, Alberta

The Long Coulee area is located approximately 30 miles north of the city of Lethbridge. Masters has an average 27 percent working interest in 1,918 (523 net) acres of undeveloped land and 11 (4.4 net) producing oil wells in this area.

Total proved reserves in this area were estimated by McDaniel in the McDaniel Report to be 107 mbbls of crude oil and 52 mmcf of natural gas at December 31, 2004.

Production from the Long Coulee area averaged 33 bbls/d of crude oil and 15 mcf/d of natural gas for the year ended December 31, 2004.

McLeans Creek, Alberta

The McLeans Creek area is located approximately 35 miles west of the town of High Prairie. Masters has an average working interest of 47 percent in 39,680 (18,452 net) acres of undeveloped land and three (1.4 net) producing oil wells in this area. The primary crude oil exploration target is the Granite Wash zone, with secondary natural gas targets in the Bluesky and Paddy zones. During 2004 Masters drilled and abandoned one well.

Total proved crude oil reserves in this area were estimated by McDaniel in the McDaniel Report to be 53 mbbls at December 31, 2004.

Production from the McLeans Creek area averaged 28 bbls/d of crude oil for the year ended December 31, 2004.

Robin, Alberta

The Robin area is located approximately 20 miles northeast of the city of Lethbridge. Masters has an average working interest of 70 percent in 2,530 (1,644 net) acres of land and five (4.0 net) producing natural gas wells in this area.

During 2004 two (1.4 net) wells were drilled resulting in one (0.6 net) natural gas well and one (0.8 net) well suspended.

Total proved reserves in this area were estimated by McDaniel in the McDaniel Report to be 724 mmcf of natural gas and 2 mbbls of NGL at December 31, 2004.

Annualized production from the Robin area averaged 1 bbls/d of NGL and 331 mcf/d of natural gas for the year ended December 31, 2004.

MANAGEMENT'S DISCUSSION & ANALYSIS

Other properties and projects
Edson, Alberta

Masters has a 30 percent working interest in 2.5 sections of land in the Edson area, 100 miles west of Edmonton. An exploratory well targeting the Banff, Elkton and Gething formations was drilled in mid-2004.

Total proved reserves in this area were estimated by McDaniel in the McDaniel Report to be 71 mmcf of natural gas and 1 mbbls of NGL at December 31, 2004.

The well was tied-in and commenced production in November 2004 at 180 mcf/d net to Masters. Annualized production from the well averaged 10 mcf/d during 2004.

Firebird, Alberta

The Firebird area is located approximately 150 miles north of the town of Slave Lake. Masters has a 100 percent working interest in 160 acres of developed land and one (1.0 net) shut-in natural gas well in this area.

Total proved reserves in this area were estimated by McDaniel in the McDaniel Report to be 690 mmcf of natural gas and 33 mbbls of crude oil and NGL at December 31, 2004.

The Firebird area did not have any production for the year ended December 31, 2004. The well produced from May through November of 2003, when it was shut-in awaiting throughput capacity at a third party processing facility. Production is expected to recommence in mid-2005.

Minor properties

Masters has additional minor producing properties in the Brazeau and Retlaw areas of southern Alberta.

Oil and gas wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2004.

	Producing		Non-producing		Producing		Non-producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
(wells)								
Alberta	43	28.9	15	9.2	21	13.9	3	3.0
Total	43	28.9	15	9.2	21	13.9	3	3.0

Properties with no attributable reserves

The following table sets out the Company's developed and undeveloped land holdings as at December 31, 2004.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
(acres)						
Alberta	31,599	19,508	157,856	83,426	189,455	102,934
Total	31,599	19,508	157,856	83,426	189,455	102,934

The Company expects that rights to explore, develop and exploit 15,712 net acres of its undeveloped land holdings will expire by December 31, 2005.

Forward contracts

Masters sells crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters natural gas production is sold to natural gas aggregators at spot market prices.

Masters does not have any hedge commitments in place at December 31, 2004.

Additional information concerning abandonment and reclamation costs

The Company estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities through its previous experience, where available, or by estimating such costs. The Company expects to incur abandonment and reclamation costs on 166 gross wells (114.4 net wells) including currently producing, non-producing wells and service wells as indicated above.

	Constant pricing		Forecast pricing		Forecast pricing	
	Proved NPV0%	Proved NPV10%	Proved NPV0%	Proved NPV10%	Proved plus probable NPV0%	Proved plus probable NPV10%
($ thousands)						
Associated with producing wells	1,719	1,315	2,295	1,747	2,295	1,747
Associated with non-producing, shut-in or no assigned reserves to wells	530	405	588	463	644	345
Total	2,249	1,720	2,883	2,210	2,939	2,092
Portion forecasted to be paid in next 3 years	266	221	281	234	281	234

MANAGEMENT'S DISCUSSION & ANALYSIS

Tax horizon

The income taxes deducted in the calculation of future net revenue above assumes a blow down scenario whereby the Company produces out its existing reserves. Under this scenario the Company is taxable in 2006. The Company forecasts its tax horizon assuming a continuing business model whereby it reinvests cash flow at historic capital efficiencies in order to achieve minimum production and reserves growth. Under this scenario the Company does not forecast being in a taxable position in 2005. The results are dependent upon commodity prices and capital spending levels.

Capital expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Company's activities for the year ended December 31, 2004.

($ thousands)	
Property acquisition costs - unproved properties	889
Exploration costs	6,563
Development costs	3,468
Total	10,920

Exploration and development activities

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2004.

(wells)	**Gross**	**Net**
Light and medium oil	-	-
Natural gas	10	6.4
Dry	9	6.6
Total	19	13.0

For details on the most important current and likely exploration and development activities during 2004, see Principal Properties.

Production estimates

The following table sets out the volume of the Company's production estimated for the year ended December 31, 2005 which is reflected in the estimate of proved reserves future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Light and medium oil	***Natural gas***	***Natural gas liquids***	***Total production***
	(bbls/d)	*(mcf/d)*	*(bbls/d)*	*(boe/d)*
2005	586	3,403	14	1,167

MANAGEMENT'S DISCUSSION & ANALYSIS

Production history

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	Quarter ended 2004			
	Dec 31	***Sep 30***	***Jun 30***	***Mar 31***
Average daily production (1)				
Light and medium crude oil *(bbls/d)*	588	597	556	488
Natural gas *(mcf/d)*	2,406	1,980	1,653	800
NGL *(bbls/d)*	13	5	9	2
Combined *(boe/d)*	1,002	932	841	619
Average price received				
Light and medium crude oil *($/bbl)* (3)	36.90	38.15	37.10	33.60
Natural gas *($/mcf)*	6.62	6.24	6.51	7.35
NGL *($/bbl)*	50.72	40.20	36.86	45.11
Combined *($/boe)*	38.09	37.90	37.95	35.82
Royalties paid				
Light and medium crude oil *($/bbl)*	6.63	7.82	6.16	6.41
Natural gas *($/mcf)*	1.48	1.14	1.23	1.74
NGL *($/bbl)*	16.21	18.50	7.04	13.04
Combined *($/boe)*	8.00	7.53	6.57	7.26
Operating expenses (2)				
Light and medium crude oil *($/bbl)*	9.82	12.23	10.26	5.75
Natural gas *($/mcf)*	1.26	1.18	1.60	1.84
NGL *($/bbl)*	-	-	-	-
Combined *($/boe)*	8.78	10.38	10.03	6.87
Netback received (2)				
Light and medium crude oil *($/bbl)*	20.45	18.10	20.68	21.44
Natural gas *($/mcf)*	3.88	3.92	3.68	3.77
NGL *($/bbl)*	34.51	21.70	29.82	32.07
Combined *($/boe)*	21.31	19.99	21.35	21.69

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues. Operating costs have not been allocated to natural gas liquids netback presented but are borne by the primary product natural gas.

(3) Includes hedge charge of $0.01 per bbl for the quarter ended December 31 and $4.25 per bbl for the quarter ended September 30.

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2004.

	Light and medium crude oil	Natural gas	NGL	Total
	(bbls/d)	(mcf/d)	(bbls/d)	(boe/d)
Little Bow	466	201	1	501
Badger	-	359	2	62
Eyremore	1	279	1	48
Iron Springs	-	412	-	69
Robin	-	331	1	56
Other	91	124	2	113
Total Alberta	558	1,706	7	849

For the year ended December 31, 2004, approximately 60 percent of Masters gross revenue was derived from crude oil production and 40 percent was derived from natural gas production.

Marketing

Masters sells its crude oil to major crude oil aggregators under short-term floating price crude oil sales contracts, with the majority of production pipeline-connected. Masters natural gas production is sold to natural gas aggregators at spot market prices. Masters does not have any hedge commitments in place at December 31, 2004.

MANAGEMENT'S REPORT

All of the information in this annual report is the responsibility of management. The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. The financial information throughout the annual report has been reviewed to ensure consistency in all material respects with that in the financial statements.

The Company maintains appropriate systems of internal control to give assurance that transactions are authorized, to safeguard assets from loss or unauthorized use and to produce reliable and accurate financial records for the preparation of financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee. The Committee, composed entirely of independent Directors, meets as least on a quarterly basis with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the financial statements before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of external auditors.

KPMG LLP, an independent firm of chartered accountants, has been engaged to audit the financial statements in accordance with generally accepted auditing standards and to provide their auditors' report on behalf of the shareholders. Their report is presented with the financial statements.

Geoff C. Merritt
President and Chief Executive Officer
March 3, 2005

Randall P. Boyd
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Masters Energy Inc.

We have audited the balance sheet of Masters Energy Inc. as at December 31, 2004 and the statement of earnings (loss) and retained earnings (deficit) and cash flows for the year ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on those financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted audit standards. Those standards require we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and the result of operations and its cash flows for the year ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

The financial statements as at December 31, 2003 and for the period then ended, were reported on by another firm of chartered accountants.

KPMG LLP

Chartered Accountants
Calgary, Alberta
[illegible] 2005

BALANCE SHEETS

As at December 31

($ thousands)		***2004***		***2003***
Assets				
Current assets				
Cash and cash equivalents	$	**-**	$	9,515
Accounts receivable		**2,116**		172
Prepaid expenses and deposits		**415**		49
		2,531		9,736
Property and equipment *(note 4)*		**34,760**		8,552
	$	**37,291**	$	18,288
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	$	**3,223**	$	346
Bank debt *(note 5)*		**3,424**		-
		6,647		346
Asset retirement obligations *(note 6)*		**3,044**		1,198
Future income taxes *(note 10)*		**30**		271
		9,721		1,815
Shareholders' equity				
Share capital and warrants *(note 7)*		**27,042**		16,545
Contributed surplus *(note 8)*		**210**		38
Retained earnings (deficit)		**318**		(110)
		27,570		16,473
	$	**37,291**	$	18,288

See accompanying notes to the financial statements.

Approved on behalf of the Board of Directors,

William R. Stedman, *Director*

Douglas H. Mitchell, *Director*

STATEMENTS OF EARNINGS (LOSS) AND RETAINED EARNINGS (DEFICIT)

For the year ended December 31, 2004 and the period August 28, 2003 to December 31, 2003

($ thousands, except share and per share amounts)	*2004*	*2003*
Revenue		
Petroleum and natural gas sales	$ 11,709	$ 192
Royalties, net of Alberta Royalty Tax Credit	(2,110)	(24)
	9,599	168
Expenses		
Operating	2,853	37
General and administrative	1,077	230
Interest	112	-
Depletion, depreciation and accretion	4,467	39
	8,509	306
Earnings (loss) before taxes	1,090	(138)
Taxes *(note 10)*		
Capital taxes	-	6
Future income taxes (reduction)	622	(34)
	622	(28)
Net earnings (loss)	428	(110)
Retained earnings (deficit), beginning of period	(110)	-
Retained earnings (deficit), end of period	$ 318	$ (110)
Earnings (loss) per share - basic and diluted *(note 9)*	$ 0.03	$ (0.03)
Weighted average number of shares outstanding		
Basic	13,521,707	3,812,834
Diluted	13,716,226	3,812,834

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the year ended December 31, 2004 and the period August 28, 2003 to December 31, 2003

($ thousands)	**2004**	**2003**
Operating activities		
Net earnings (loss)	**$ 428**	$ (110)
Add (deduct) non-cash items		
Depletion, depreciation and accretion	**4,467**	39
Asset retirement expenditures	**(95)**	-
Future income taxes (reduction)	**662**	(34)
Stock-based compensation expense	**172**	38
	5,634	(67)
Changes in non-cash working capital	**731**	(142)
	6,365	(209)
Financing activities		
Proceeds on share issue	**-**	16,850
Repayment of bank loan *(note 1)*	**(7,032)**	-
	(7,032)	16,850
Changes in non-cash working capital	**3,424**	146
	(3,608)	16,996
Investing activities		
Property and equipment	**(10,920)**	(7,393)
Costs related to the acquisition of Terraquest *(note 1)*	**(295)**	-
	(11,215)	(7,393)
Changes in non-cash working capital	**(1,057)**	121
	(12,272)	(7,272)
Increase (decrease) in cash	**(9,515)**	9,515
Cash and cash equivalents, beginning of period	**9,515**	-
Cash and cash equivalents, end of period	**$ -**	$ 9,515
Supplemental cash flow information		
Interest income received	**$ 28**	$ 55
Interest paid	**$ 56**	$ -
Capital taxes paid	**$ 34**	$ -

See accompanying notes to the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2004 and the period August 28, 2003 to December 31, 2003
(Tabular amounts in $ thousands, except share and per share amounts)

1. DESCRIPTION OF THE COMPANY AND BUSINESS COMBINATION

On February 26, 2004, Masters Energy Inc. ("the Company"), a private company incorporated under the Alberta Business Corporations Act on August 28, 2003 and Terraquest Energy Corporation, a public company listed on the Toronto Stock Exchange, amalgamated and the combined company ("Amalco") continued under the name and management of Masters Energy Inc. The transaction saw Terraquest shareholders receive one Amalco Common Share for every 12 common shares of Terraquest and Masters shareholders receive one Amalco Common Share for every two common shares or special warrants of Masters. After giving effect to the transaction, Amalco had approximately 14.4 million Common Shares outstanding, of which former Masters securityholders owned approximately 62 percent and former Terraquest shareholders owned approximately 38 percent. The name of the combined company is "Masters Energy Inc.". The comparative figures are those of Masters Energy Inc.

The business combination has been accounted for using the purchase method as a reverse takeover of Terraquest by the Company and earnings of Terraquest are recognized from the closing date of February 26, 2004.

The Terraquest purchase was valued based on the discounted proved plus probable reserves acquired as determined by an independent reserves evaluation. Land cost values were estimated by Masters staff. The share consideration value of acquiring Terraquest was based on Masters common share fair value at the date of amalgamation. The purchase price was allocated as follows:

Property and equipment	$	19,584
Future tax asset		903
Working capital deficiency		(694)
Fair value of hedging commitment		(199)
Bank debt		(7,032)
Asset retirement obligations		(1,770)
	$	10,792
Purchase price		
Share consideration	$	10,497
Acquisition costs		295
	$	10,792

The Company is engaged in the exploration, development and production of petroleum and natural gas in western Canada.

NOTES TO THE FINANCIAL STATEMENTS

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation

The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(b) Cash and cash equivalents

Cash and cash equivalents consisted of amounts on deposit with banks and term deposits with original maturities of less than 90 days.

(c) Property and equipment

The Company follows the full cost method for accounting for petroleum and natural gas operations whereby all costs related to the exploration for and the development of petroleum and natural gas reserves are capitalized. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and production and well equipment.

Costs capitalized together with future capital costs are depleted and depreciated using the unit-of-production method based upon gross proved petroleum and natural gas reserves as determined by independent qualified reserves evaluators at future prices and costs. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content, where one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The cost of significant unproved properties are excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

The Company performs a ceiling test for impairment for each cost centre in a two-stage test undertaken at least annually.

(i) Impairment is recognized if the carrying value of the petroleum and natural gas properties, less accumulated depletion and depreciation, exceeds the estimated future cash flows from proved oil and natural gas reserves, on an undiscounted basis, using forecast prices and costs and the lower of cost and fair value of unproven properties. Future cash flows are calculated before interest, general and administrative expenses and income taxes.

(ii) If impairment is indicated by applying the calculations described in (i) above, the Company will measure the amount of the impairment by comparing the carrying value of the petroleum and natural gas properties less accumulated depletion and depreciation to the estimated future cash flows from the proved and probable oil and natural gas reserves, discounted at a risk-free rate of interest, using forecast prices and costs and the lower of cost and fair value of unproven properties. Any impairment recognized is recorded as additional depletion and depreciation expense.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion and depreciation by 20 percent or more.

The costs of corporate and other office equipment are amortized at rates approximating their useful life on a declining balance basis of 30 percent per year.

(d) Joint ventures

Substantially all of the Company's exploration and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(e) Asset retirement obligations

The Company recognizes the liability for retirement obligations associated with the abandonment of petroleum and natural gas wells, related facilities, compressors and plants, removal of equipment from leased acreage and returning such land to its original condition. The fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by Company management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related oil and natural gas properties, and a corresponding liability is recognized. This component of the increase in petroleum and natural gas properties is depleted and depreciated on the same basis as the remainder of the petroleum and natural gas properties. The liability is adjusted for accretion charged to income until the obligation is settled or sold and for revisions to the estimated cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

(f) Flow-through shares

From time to time, the Company issues flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital is reduced and a future tax liability is recorded equal to the estimated amount of future income taxes payable by the Company as a result of the renunciations, when the expenditures are renounced.

NOTES TO THE FINANCIAL STATEMENTS

(g) Stock-based compensation

The Company issues stock options and performance warrants to directors, officers, employees and other service providers. Compensation cost, attributable to stock options and performance warrants granted, is measured by the fair value method of accounting at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. When stock options or performance warrants are exercised, the cash proceeds together with the amount previously recorded as contributed surplus are recorded as share capital. The Company does not incorporate an estimated forfeiture rate for stock options and performance warrants that will not vest, but accounts for forfeitures as they occur.

(h) Revenue recognition and operating expenses

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(i) Income taxes

Future income taxes are accounted for using the liability method of income tax allocation. Under the liability method, income tax assets and liabilities are recorded to recognize future tax income inflows and outflows arising from the settlement or recovery of assets and liabilities at the carrying values. Income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those liabilities are more likely than not to be realized. Future income tax assets and liabilities are determined based on the income tax laws and rates that are anticipated to apply in the period of reversal.

(j) Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. The Company utilizes the treasury stock method for the calculation of diluted per share amounts. This method assumes that the proceeds from the exercise of in-the-money stock options and warrants plus the unamortized stock based compensation are used to repurchase Company shares at the weighted average market price during the period.

(k) Measurement uncertainty

The amounts recorded for depletion and depreciation of oil and gas properties, the asset retirement obligation and the ceiling test are based on estimates. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions.

The amounts disclosed relating to the fair value of stock options and performance warrants issued and the resulting income effect are based on estimates of the future volatility of the Company's share price, expected lives of the options, expected dividends and other relevant assumptions.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

(l) Financial instruments

The Company has a price risk management program whereby the commodity price associated with a portion of its future production can be fixed. The Company is able to sell forward a portion of its future production through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward and future contracts are subject to market risk from fluctuating commodity prices and exchange rates; however, gains or losses on the contracts are offset by changes in the value of the Company's production and recognized in income in the same period and category as the hedged item.

3. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation costs are presented as an operating expense in the Statement of Earnings and Retained Earnings. The new standard defines the sources of Generally Accepted Accounting Principles ("GAAP") and effectively eliminates industry practice as a source of GAAP. Previously, as was industry practice, transportation costs were deducted from petroleum and natural gas revenue.

4. PROPERTY AND EQUIPMENT

As at December 31, 2004	*Cost*	*Accumulated depletion and depreciation*	*Net book value*
Petroleum and natural gas properties and well equipment	**$ 39,052**	**$ 4,317**	**$ 34,735**
Office equipment	**42**	**17**	**25**
	$ 39,094	**$ 4,334**	**$ 34,760**
As at December 31, 2003			
Petroleum and natural gas properties and well equipment	$ 8,550	$ 34	$ 8,516
Office equipment	41	5	36
	$ 8,591	$ 39	$ 8,552

The value of undeveloped lands excluded from costs subject to depletion was $5.5 million at December 31, 2004 ($nil - December 31, 2003).

As at December 31, 2004, $0.5 million ($nil - December 31, 2003) of general and administrative costs were capitalized.

The benchmark and Company prices on which the December 31, 2004 ceiling test for impairment is based, are as follows:

	Oil		Natural gas		Natural gas liquids	
	Bow River medium benchmark	Company	AECO Spot benchmark	Company	Edmonton benchmark	Company
	($/bbl)	($/bbl)	($/GJ)	($/mcf)	($/bbl)	($/bbl)
2005	$ 37.00	$ 37.37	$ 6.45	$ 6.63	$ 37.20	$ 41.59
2006	37.10	36.89	6.20	6.40	35.10	39.12
2007	34.60	33.99	6.05	6.38	33.00	39.63
2008	32.70	31.65	5.80	5.99	31.20	37.44
2009	32.20	30.73	5.70	5.83	30.80	35.76
2010	32.00	30.45	5.60	5.64	30.50	33.41

Prices increase at a rate of approximately two percent per year for oil, natural gas and natural gas liquids after 2010. Adjustments were made to the benchmark prices, for purposes of the ceiling test, to reflect varied delivery points and quality differentials in the products delivered.

5. BANK DEBT

The Company has access to a demand revolving credit facility with a Canadian chartered bank to a maximum of $8.5 million. The facility may be drawn down or repaid at any time and bears interest at prime plus 0.2 percent per annum. The credit will revolve until May 25, 2005, at which time a review of the facility will occur.

The Company has available a $2.5 (USD) million demand swap facility, to assist in financing the contingent exposure of settlement for financial commodity swaps. The facility bears interest at a US base rate plus 0.2 percent per annum on amounts drawn.

As of December 31, 2004, $3.4 million ($nil - December 31, 2003) has been drawn against the revolving credit facility.

Security pledged for the facilities consists of a general assignment of book debts, a $25.0 million demand debenture, secured by a first floating charge over all the assets of the Company. The nature of the lending facility is such that it is recognized as a current liability. The Company is not in breach of any covenants under its credit facility.

NOTES TO THE FINANCIAL STATEMENTS

6. ASSET RETIREMENT OBLIGATION

The following table summarizes changes in the asset retirement obligation for the years ended December 31, as indicated:

		2004		2003
Asset retirement obligation, beginning of period	$	1,198	$	-
Adjustments		(119)		-
Liabilities acquired		1,770		1,198
New drilling		119		-
Asset retirement expenditures		(95)		-
Accretion expense		171		-
Asset retirement obligation, end of period	$	3,044	$	1,198

The total estimated, undiscounted cash flows required to settle the obligations, before considering salvage, is $4.4 million which has been discounted using a weighted average credit-adjusted risk-free interest rate of 6.9 percent. The Company expects these obligations to be settled in approximately 1 to 14 years.

7. SHARE CAPITAL AND WARRANTS

(a) Authorized

Unlimited number of voting common shares, without nominal or par value.
Unlimited number of preferred shares, issuable in series, with rights and privileges to be determined at the time of issuance by the Board of Directors.

(b) Issued

	Number		Amount
Common shares issued on incorporation	1	$	-
Special warrants			
Common special warrants issued pursuant to private placements	16,002,000		16,002
Flow-through special warrants issued, pursuant to private placements (net of future taxes of $630,000)	1,750,000		1,120
	17,752,001		17,122
Issuance costs (net of future taxes of $325,000)	-		(577)
Warrants and shares balance, December 31, 2003	17,752,001		16,545
Warrants and shares exchanged per plan of arrangement	(17,752,001)		-
Issued to Masters Energy Inc. shareholders on reverse takeover of Terraquest *(Note 1)*	8,876,000		-
Issued to Terraquest shareholders at date of acquisition *(Note 1)*	5,487,647		10,497
Balance, December 31, 2004	**14,363,647**	**$**	**27,042**

NOTES TO THE FINANCIAL STATEMENTS

On October 28 and November 25, 2003, the Company closed private placements of 16,002,000 common special warrants and 1,750,000 flow-through special warrants for gross proceeds of $17.8 million. Both the common special warrants and flow-through special warrants were issued at $1.00 per special warrant, were convertible to common shares at a rate of one warrant to one common share at no additional cost upon either demand, or the Company obtaining a public listing. If the Company's shares were not listed on a public exchange within one year of issuance, the warrants would be automatically converted at a rate of one warrant for 1.1 common shares. The Company has renounced expenditures relating to the 1,750,000 flow-through special warrants effective December 31, 2003. All of the required expenditures were incurred during 2004. Effective February 26, 2004, all special warrants were converted into common shares.

(c) Terraquest flow-through share program

The Company was required to incur $1.8 million of qualifying expenditures during the balance of 2004 to fulfill the obligations of a Terraquest flow-though share program entered into in 2003. All of the required expenditures were incurred during 2004.

8. STOCK-BASED COMPENSATION PLANS

On February 26, 2004, the Company's stock - based compensation plans were revised to conform with the one for two share consolidation related to the acquisition of Terraquest Energy Corporation. This had the effect of halving the number of options and warrants that had been issued and doubling their exercise price. The plans are described below:

(a) Stock options

The Company's stock option plan allows for options to be granted to employees, officers, directors and other service providers. The number of shares which may be issued, and that have been reserved, under the plan is 1,435,042 common shares. The maximum number of shares that may be reserved for issuance to any one person under the plan is limited to 5 percent per year of the issued and outstanding Common Shares and Special Warrants for employees, officers and directors and 2 percent for other service providers. The plan also provides that the price at which options may be granted cannot be less than the market price of the common shares at the date of grant. Options granted under the plan have a maximum life of 5 years and vest at an equal amount over three years on the anniversary date of the grant or as determined by the Board of Directors.

The following tables summarizes information about the Company's stock options outstanding at December 31, 2004:

	Number of options	*Weighted average exercise price*
		($)
Balance, December 31, 2003	575,000	2.00
Granted, April 26, 2004	655,000	2.35
Granted, December 23, 2004	25,000	2.60
Balance, December 31, 2004	**1,255,000**	**2.19**

NOTES TO THE FINANCIAL STATEMENTS

Exercise price per share	*Options outstanding*	*Weighted average years to expiry*
($)		
2.00	575,000	4.0
2.35	655,000	4.3
2.60	25,000	5.0
2.00 - 2.60	1,255,000	4.2

As of December 31, 2004, 191,667 stock options have vested at an exercise price of $2.00 per option and none of the vested options have been exercised.

The Company has recorded compensation expense of $0.2 million as at December 31, 2004, ($37,000 - December 31, 2003) for options and warrants vested during the period. Using the Black-Scholes model, assuming the expected life of the options and warrants are 5 years and no expected future dividends, the following table summarizes the total fair value of options and warrants granted.

Grant date	*Options and warrants granted*	*Expected volatility*	*Risk-free interest rate*	*Total fair value*
		(%)	*(%)*	*($ thousands)*
December 23, 2004	25,000	33	3.40	21
April 26, 2004	655,000	26	3.40	455
December 22, 2003	1,575,000	nil	3.95	207

(b) Performance warrants

The Company's Performance Warrants Plan allows for Performance Warrants to be granted to employees, officers and directors. The maximum number of shares which may be issued, and that have been reserved, under the plan is 1,000,000 common shares. Performance Warrants granted under the plan have a five year life, vest immediately and have no performance criteria other than the escalating exercise price. All 1,000,000 Performance Warrants have been granted, expiring December 22, 2008, with the following exercise prices:

Performance warrants outstanding	*Average exercise price per warrant*
	($)
100,000	2.00
100,000	2.50
150,000	3.00
150,000	3.50
250,000	4.00
250,000	4.50
1,000,000	3.55

No performance warrants were exercised during the reporting period.

NOTES TO THE FINANCIAL STATEMENTS

9. PER SHARE AMOUNTS

Earnings per share has been calculated using the basic weighted average number of common shares outstanding of 13,521,707 (3,812,834 - 2003) during the year ended December 31, 2004. As at December 31, 2004, a total of 194,519 (nil - 2003) were added to the total to take into account the dilutive effect of the options for the year. For comparative reporting purposes the 2003 weighted average number of shares indicate the consolidation effect on the common shares that resulted from the acquisition of Terraquest Energy Corporation.

10. TAXES

(a) The provision for income tax expense differs from that which would be expected from applying the combined effective Canadian federal and provincial income tax rate of 38.62 percent (40.62 percent - 2003) to income before income taxes. The difference results from the following:

		2004		*2003*
Expected income tax expense (reduction)	**$**	**423**	$	(56)
Increase (decrease) resulting from:				
Non-deductible crown payments		**565**		9
Resource allowance		**(480)**		(8)
Change in effective tax rate applied		**(111)**		6
Stock-based compensation expense		**67**		15
Other		**198**		-
Capital tax		**-**		6
Total tax expense (reduction)	**$**	**662**	$	(28)

(b) The components of the future income tax liability at December 31 are as follows:

		2004		*2003*
Carrying value of property and equipment in excess of available tax deductions	**$**	**2,141**	$	1,108
Asset retirement obligation		**(987)**		(402)
Non-capital loss carryforwards		**(640)**		(133)
Share issuance costs		**(484)**		(302)
	$	**30**	$	271

NOTES TO THE FINANCIAL STATEMENTS

11. COMMITMENTS

As at December 31, 2004, the Company is committed under a lease on its office premises expiring August 2005 for future annual minimum rental payments excluding estimated operating costs of $30,000.

12. FINANCIAL INSTRUMENTS

(a) Fair values

The fair values of the Company's accounts receivable, accounts payable and accrued liabilities and bank debt approximate their carrying values due to their short-term maturity.

(b) Credit risk

The Company's credit risk is limited to the carrying amount of its accounts receivable, which are due primarily from other entities involved in the oil and gas industry. These amounts are subject to the same risks as the industry as a whole.

(c) Interest rate risk

The Company is exposed to interest rate risk to the extent the changes in market interest rates will impact the Company's debts that have a floating interest rate.

13. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2004, the Company incurred legal fees related to general corporate administration and the acquisition of Terraquest of $0.2 million ($0.1 million - December 31, 2003) to a law firm in which a director of the Company is a partner. This transaction has been recorded at the exchange amount, which is the amount agreed to by the parties.

ANNUAL MEETING OF SHAREHOLDERS

The Metropolitan Centre
333 - 4 Avenue SW
Calgary, Alberta
Tuesday, May 3, 2005 at 2:00 pm (Calgary time)

CORPORATE INFORMATION

DIRECTORS

Fred Coles[1,3]
Calgary, Alberta
President of Menehune Resources Ltd.

Kerry Lyons[3]
DeWinton, Alberta
President and CEO of Greenfield Resources Ltd.

Geoffrey C. Merritt[2]
Calgary, Alberta
President and CEO of Masters Energy Inc.

Douglas H. Mitchell[2]
Calgary, Alberta
Co-Chairman and Managing Partner of Borden Ladner Gervais LLP

John W. (Jack) Peltier[1,2]
Calgary, Alberta
President of Ipperwash Resources Ltd.

William R. Stedman[1,3]
Calgary, Alberta
Chairman and CEO of ENTx Capital Corporation

(1) *Audit Committee*
(2) *Compensation Committee*
(3) *Reserves Committee*

OFFICERS

Geoffrey C. Merritt
President and Chief Executive Officer

Randall P. Boyd
Chief Financial Officer

Peter W. Goodman
Controller

INDEPENDENT QUALIFIED RESERVES EVALUATOR

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Borden Ladner Gervais LLP
Calgary, Alberta

STOCK EXCHANGE AND LISTING

Toronto Stock Exchange "TSX"
Trading Symbol "MSY"

TRANSFER AGENT AND REGISTRAR

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AUDITOR

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BANK

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